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It is critical for the success of bioenergy and bioproduct industries to maintain or improve soil, surface water, and ecosystem quality.

- The quality of soil is impacted by:
  - **Increased soil carbon** generally results in positive impacts on soil nutrients, erosion, and soil structure
  - **Soil nutrients** could be removed by erosion and harvest if not managed
  - **Erosion** is one of the greatest threats to long term soil productivity
    - Leads to a loss of adequate depth of rooting, water retention and nutrient rich surface layers
  - **Compaction** and loss of soil cover increase nitrification rates, damages soil structure, increases runoff, and decreases water storage
- Management of run-off (e.g. water with nitrate, phosphorous, pesticides, and herbicides) so that nearby surface water supplies are unaffected
- Landscape diversity is necessary to maintain regional plant and animal species diversity and ecosystem health
- Especially where public lands are being converted to biomass production, adaptation of production methods may be required to allow multi-purpose land-use
- Poor management practices could seriously reduce public acceptance of biomass

Proper management of agricultural residue collection is key to maintain soil quality and to avoid erosion and increased runoff contamination.

- Sufficient residues must be left on the field to maintain soil carbon
  - The fraction of residues that must be left on the field varies from site to site
  - Soil carbon balances are being taken into account in many agricultural crop residue feedstock analyses
- Erosion control must be maintained with agricultural residue collection
  - Erosion models and field data identify amounts of residues that must be left on the field to significantly reduce impact on highly erosive sites
  - Agricultural crop residue feedstock analyses are applying erosion factors and are excluding lands with high erosion indices from residue collection[1]
- Soil compaction can occur with agricultural residue collection if not properly managed
  - Harvesting and collection equipment and practices must minimize passes and soil compaction
- Agricultural residue collection offers potential benefit in the reduction of airborne particulates by decreasing the frequency of in-field residue burns
- Leaving residues for soil carbon and erosion protection can minimize run-off contamination concerns

[1] This is a work in progress by Oak Ridge National Laboratory (ORNL)

Converting traditional crop lands into energy crop production could increase soil carbon and nutrients.

- Extensive rooting systems and litter of some energy crops can increase soil carbon compared to traditional crops
  - Perennial grasses were found to replace 23% of soil carbon lost during decades of prior tillage[1]
- Studies have found soil carbon increases after three growing seasons on sites planted with short rotation wood crops[2] (SRWC) and switchgrass compared to traditional crops[3]
- Energy crop nutrients removed through runoff and harvesting are somewhat less compared to traditional crops[1]
- Energy crop harvest timing can conserve soil nutrients
  - After the growing season, plant nutrients can translocate to the roots and are not removed with harvest

[1] Mann, L. and V. Tolbert (2000). "Soil Sustainability in Renewable Biomass Plantings", Royal Swedish Academy of Sciences 2000, Ambio Vol. 29, no. 8.

[2] Short rotation woody crops such as sweetgum, sycamore, and cottonwood.

[3] Tolbert, V., et al. (2000). "Increasing below-ground carbon sequestration with conversion of agricultural lands to production of bio-energy crops", New Zealand Journal of Forestry Science, Vol. 30, p. 138-149.

Energy crop production can have erosion concerns unless precautions are taken.

- New plantings of woody energy crops (such as poplar) and bunchgrasses (such as switchgrass) can result in levels of erosion similar to tilled agricultural fields
- Using cover crops can reduce erosion by 64% during the early years of stand development[2]
  - However, competition by cover crops could reduce growth[3]
  - Different cover crops and management practices may reduce potential competition[2]
- Erosion after the second year of energy crop establishment are as low as or lower than losses with no-till corn[1]
- Energy crops should reduce compaction due to fewer equipment passes annually and over the energy crop lifetime

[1] Mann, L. and V. Tolbert (2000). "Soil Sustainability in Renewable Biomass Plantings", Royal Swedish Academy of Sciences 2000, Ambio Vol. 29, no. 8.
[2] Malik, R.K., et al. (2000). "Use of Cover Crops in Short Rotation Hardwood Plantations to Control Erosion", Biomass and Bioenergy, Vol. 18, p. 479-487.
[3] There is a work in progress to investigate this issue, see note 2.

Converting traditional crop lands into energy crop production could result in benefits of reduced runoff contamination and improved biodiversity.

- Converting traditional cropland to energy crops can result in reduced nitrate, phosphorous, pesticides, and herbicides[1] in runoff
  - In field studies, subsurface herbicide transport did not occur and off-site chemical transport was minimal compared with traditional crops[2]
- Willow, poplar, and grasses have been used to remove nutrients and metal contaminates from waste water, historical agricultural applications, and contaminated shallow groundwater
- Surveys have shown that breeding birds and small mammals use hybrid poplars and short-rotation woody crops more extensively than traditional row crops[3]
  - However, use was lower than in surrounding forested areas and habitat sensitive birds did not use the energy crop plantings
- Establishing energy crops adjacent to diverse land use and providing within it planting diversity can increase their quality and use for wildlife

[1] Mann, L. and V. Tolbert (2000). “Soil Sustainability in Renewable Biomass Plantings”, Royal Swedish Academy of Sciences 2000, Ambio Vol. 29, no. 8.
[2] Tolbert, V.R. (2000). “Ensuring Environmentally Sustainable Production of Dedicated Biomass Feedstocks”. Bioenergy 2000. The Ninth Biennial Bioenergy Conference, October 15-19, 2000.
[2] Lindberg, J.E, et al. (1998). “Determining Biomass Crop Management Strategies to Enhance Habitat Value for Wildlife”. Bioenergy ‘98, Vol. II, p. 1322-1332.

Less productive, erosive, or degraded agricultural lands are anticipated to be used initially for energy crop production.

- The potential for environmental impacts from site preparation and production on these lands is greater and the yields probably less than on more productive lands
- However, environmental gains and benefits, especially in soil quality and carbon storage, are expected[1]
- Minimizing environmental impacts through proper management practices will be required
- Management practices will need to be site and energy crop or residue specific

Marginal lands need to be carefully managed to realize net benefits from energy crop production.

[1] Tolbert, V.R. (2000). "Ensuring Environmentally Sustainable Production of Dedicated Biomass Feedstocks". Bioenergy 2000. The Ninth Biennial Bioenergy Conference, October 15-19, 2000.

Forest residue collection must be managed properly to prevent erosion and realize benefits from fire prevention.

- Residue collection as a means to combat uncontrolled forest fires could potentially reduce:
  - Unwanted air borne particulates
  - Habitat destruction
  - Animal and human fatalities
- Proper management is required in order to reap net benefits
  - Residue collection on steep slopes or highly erosive soils could result in erosion
  - Increased soil compaction could occur if additional equipment is required
  - Soil carbon could be lost if excessive removal occurs
- Residue collection management can benefit biodiversity with increased habitat and structural diversity

Bioenergy and bioproducts industries could provide environmental benefits, provided careful management practices are implemented.

- Agricultural residue collection must be managed properly to maintain and/or improve soil quality (e.g. organic matter, nutrients, and soil stability) and avoid increased runoff contamination
- Converting traditional crop lands into perennial energy crop production could yield net benefits in increased soil carbon and nutrients
  - Energy crop production can have erosion concerns unless managed properly
  - Reduced runoff contamination and improved biodiversity are additional potential benefits
- Marginal lands need to be carefully managed to realize net benefits from energy crop production
- Forest residue collection must be managed properly to prevent erosion and realize benefits from fire prevention
- Several areas of additional research are necessary to assess the potential environmental impacts and benefits of bioenergy and bioproducts industries
  - The information currently available is based on smaller scale studies
  - Studies at larger scale are needed to validate results and determine landscape scale effects

Several areas of additional research are necessary to assess the potential benefits and impacts of bioenergy and bioproducts industries.

- Effects of energy crop production on marginal lands with comparison to existing practices needs more quantification
  - Larger scale studies may be required
  - Development of appropriate management practices for different crops and sites are required
- Long term studies on energy crop effects on soil and water quality are needed
- Site-specific erosion factors[1] and collection equipment effects on soil compaction need to be analyzed for agricultural and forest residue collection
- Agricultural residue collection effects on run-off contamination needs to be evaluated
  - Additional studies are needed for the residue amount needed for sufficient soil quality and maintenance of soil carbon
- Forest residue collection effects on biodiversity needs to be evaluated
  - Additional studies are needed for the residue amount needed for sufficient soil quality and maintenance of soil carbon

[1] This is a work in progress for agricultural residue collection by ORNL.

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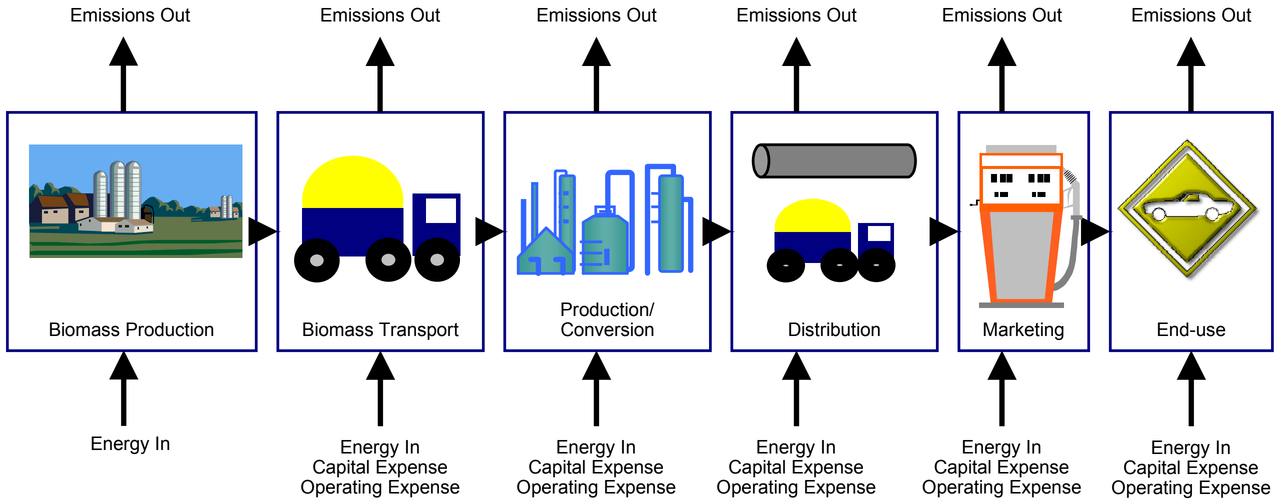
Throughout the report, each potential fuel/power/product was analyzed on a “value chain” basis: from plantation/collection site to the market of use.



Biopower, all pieces, including energy losses of transmission and distribution (but not investment costs of transmission and distribution)

Biofuels, “well to wheel” analysis, not including vehicle retrofit costs

Bioproducts, up to primary processing plant-gate

Value Chain Analysis:
- Considers all steps involved in production and use of biomass energy, fuels and products
- Incorporates multiplicative effects in value chain
- Allows for detailed analysis of each module and consideration of a range of combinations
- Considers all energy inputs into the value chain, including secondary not tertiary inputs; i.e. energy used to produce diesel for trucks is included but energy use to make the trucks or the refinery is not included

A life cycle analysis was not part of the scope of this study.

The complexity of the biopower market predicted the use of three distinct baselines for the comparison fossil alternative.

	Coal Rankine Electricity	Natural gas GTCC	Grid Average Electricity
Exploration & Production	• Emissions are associated with coal mining based on 1987 U.S. Coal Industry Statistics and DeLuchi, November 1993, based on DoC Census • Coal bed methane released during mining is included in emissions (90% vented; 10% used for fuel)	• Emissions are associated with extracting the natural gas from the well head and associated emissions from processing of the gas (e.g. removal of inerts, recoverable products (NGLs, LPG), and removal of impurities) • No gas flaring or venting included. Gas flaring associated with oil production assigned to fuels production	• Emissions are based on that from coal, natural gas, and nuclear generated power • Transmission & distribution energy losses of 7.2%
Fuel Transport	• Emissions are associated with a transportation mix of ship (18%), rail (65%), and truck (15%); transportation mix based on DeLuchi; total transport amount from 2000 data	• Emissions associated with national average pipeline for natural gas. Based on total natural gas supply since this is the amount shipped through U.S. pipelines annually.	
Electricity Generation	• Coal Rankine power production with a HHV efficiency of 32.9% • Did not include steam (heat) production credit • Transmission & distribution energy losses of 7.2%	• Natural gas-fired GTCC power production with a HHV efficiency of 54.0% • Transmission & distribution energy losses of 7.2%	

	% Mix	Efficiency
Coal	51.8	32.2%
Oil	2.4	32.6%
Gas	16.1	32.9%
Other	0.8	32.5%
Nuclear	18.4	32.5%
Other Non-fossil	10.4	32.5%

Biofuels were compared to a gasoline fuel chain or a diesel petroleum chain depending on engine use (spark versus compression ignition).

	Gasoline	Petroleum Diesel
Exploration & Production	• Petroleum extraction from Petroleum Extraction - 1987 DoC Census Data adjusted by DeLuchi (1993) including Alaska and Lower 48 Production • Includes natural gas flared during production. The natural gas is flared or used as fuel onsite • Segment efficiency 95.8%	
Raw Oil Transport	• Emissions are associated with shipping crude oil within Lower 48 and from Alaska to Lower 48 and shipping of oil imported into United States. • Modes of transport included pipeline, barge, tanker, train, and truck • Includes evaporative losses; segment efficiency of 99.1%	
Fuel Production	• Includes refining from petroleum for gasoline production with a segment efficiency of 87.8%	• Includes refining from petroleum for gasoline production with a segment efficiency of 94.8%
Fuel Distribution	• Includes emissions associated with transport of the gasoline to the bulk terminal by a combination of pipeline; tanker and barge; truck transport to the bulk plant and truck transport to the fueling stations	• Includes emissions associated with transport of the diesel to the bulk terminal by a combination of pipeline; tanker and barge; truck transport to the bulk plant and truck transport to the fueling stations
Fuel Marketing	• Includes energy usage at fueling stations and evaporative losses	• Includes energy usage at fueling stations and evaporative losses
Vehicle Use	• Use in spark ignition vehicle with 15.7% efficiency • Emissions are set to ULEV standards	• Use in CIE vehicle with 16.9% efficiency • Emissions are set to ULEV standards • Particulate matter set to 100,000 mile durability standards for new 2001-2003 Model Year TLEV vehicles

Two proxies of petroleum products were used for a high level comparison: methanol from natural gas and LPG from petroleum.

	Methanol from Natural Gas	LPG from Petroleum
Exploration & Production	• Emissions are associated with extracting the natural gas from the well head and associated emissions from processing of the gas (e.g. removal of inerts, recoverable products (NGLs, LPG), and removal of impurities)	• Petroleum extraction from Petroleum Extraction - 1987 DoC Census Data adjusted by DeLuchi (1993) including Alaska and Lower 48 Production • Includes natural gas flared during oil production • Segment efficiency 95.8%
Raw Fuel Transport	• Emissions associated with national average pipeline for natural gas. Based on Total Natural Gas Supply since this is the amount shipped through U.S. pipelines annually.	• Emissions are associated with shipping crude oil within Lower 48 and from Alaska to Lower 48 and shipping of oil imported into United States. • Modes of transport included pipeline, barge, tanker, train, and truck • Includes evaporative losses; segment efficiency of 99.1%
Primary Product Manufacture	• Methanol synthesis from synthesis gas made from natural gas with segment efficiency of 66.5%	• Includes refining from petroleum for LPG production with a segment efficiency of 95.3%

A life cycle analysis was not part of the scope of this study. This has implications in both cost of the chain and associated emissions.

	Options	What was addressed
Biomass Production & Harvesting	• Agricultural residues (e.g. corn stover, wheat straw) • Cellulosic energy crops (e.g. hybrid poplar, switchgrass)	• Emissions for agricultural residues and the main crop (e.g. corn or wheat) were assigned equal emissions on an energy basis • Estimates for agricultural residues and energy crops includes energy required for fertilizer production in addition to fuels used for farm equipment • For fertilizer use (both for agricultural residues and energy crops) the emissions are based on the energy embodied in the fertilizers (gas & electricity), neglecting energy for transportation of the fertilizer • A multiplier was used for seeds, herbicides, pesticides and assumed to be 10% of the energy embodied in fertilizer for agricultural residues and energy crops • A 50/50 mix of best available control and uncontrolled technology were used for the emission factors emissions associated with fertilizer and planting & harvesting of agricultural residues and energy crops • For energy crops we assumed that the same fuel distribution as used for corn farming; also that 1/2 of the land is not fertilized • Emissions associated with the agricultural residues remaining on the field if not used were excluded from the analysis. Similarly any emissions from lands that would have occurred if energy crop production was not used were excluded
	• Gaseous biomass • RDF • Process wastes (e.g. black liquor, hogged fuel, other solid residues)	• Biogas (including landfill, sewage, and digester gas) is generated and used where it is produced so there is no energy use (and therefore no emissions) associated with biomass "harvesting" or gathering and no subsequent transport of the resource • For biogases, fugitive CH_4 , nonmethane hydrocarbon (NMHC), and particulate matter (PM) emissions that would have occurred regardless of the end use for the biogas were also excluded • For RDF, the emissions associated with collection and processing are not included as these would need to be done regardless of the use of RDF for fuel (The non-biomass portion of RDF is also excluded). The RDF is used at the collection site so that transportation emissions are not included • Process wastes (including black liquor, hogged fuel, and other solid residues) are generated and used where produced so there is no energy use (and therefore no emissions) associated with biomass gathering and no transport of the resource
Biomass Transport	• Agricultural residues • Cellulosic energy crops	• Transportation emissions are associated with a 50-mile one-way trips using a diesel fueled truck. A 50/50 mix of best available control technology and uncontrolled was used for the emission factors • Transportation costs and associated emissions were not included for gaseous biomass; refuse derived fuel, black liquor, hogged fuel, and other solid process residues

Closed-loop carbon cycle was assumed (net zero biomass CO_2 emissions) for biopower.

	Options	What was addressed
Biopower	• Resources –Biogases (e.g. landfill, sewage, & digester gases) –Agricultural residues –Energy Crops –RDF –Black liquor –Hogged fuel –Other solid residues • Technologies included: –Rankine cycle –Gas turbine –Gas turbine combined cycle –Integrated gasification combined cycle –Internal combustion engine –Fuel cell	• CO_2 emissions from the utilization of the biomass itself are assumed to be zero (closed-loop carbon cycle) • Biogas (including landfill, sewage, & digester gas), RDF, black liquor, hogged fuel, and other solid residues are generated and used where it is produced so there is no energy use (and therefore no emissions) associated with transport. Fugitive CH_4, NMHC, & PM emissions that would have occurred regardless of the end use were also excluded • Grid-sited options (e.g. utilization of landfill gas, co-firing with coal) include the effects of transmission & distribution energy losses • Most biomass is relatively low in sulfur and therefore no controls are used. For selected feedstocks that are higher in sulfur, such as black liquor, sulfur control technology was used • Fuel cell emissions of SO_2 are effectively zero, as the fuel must be scrubbed free of sulfur to avoid poisoning of the fuel cell stack • NOx emissions estimates are consistent with typical controls (e.g., dry low NOx combustion for gas turbines, lean burn technology for internal combustion engines) • For co-firing with coal it is assumed that each percentage point of biomass co-firing (on a energy basis) results in a 2 percentage point decrease in overall NOx for direct firing and a 4 percentage point decrease for gasification co-firing (the latter is consistent with the use of the biomass as a reburn technology) • For co-firing with coal it is assumed that methane, NMHC and CO emissions are the same per BTU of fuel consumed as for the baseline coal plant, so that differences in emissions per kWh are related to differences in efficiency • For biomass co-firing with coal, the co-firing is assumed to reduce PM emissions based on the relative ash content of biomass and coal • Methane, NMHC emissions are generally uncontrolled emissions consistent with current good practices for combustion (e.g., dry low NOx combustion for gas turbines, lean burn technology for internal combustion engines) • PM emissions are generally controlled emissions consistent with current good practices (e.g., electrostatic precipitators) • CO emissions are generally uncontrolled emissions consistent with current good practices for combustion (e.g., dry low NOx combustion for gas turbines, lean burn technology for internal combustion engines)

Closed-loop carbon cycle was assumed (net zero biomass CO_2 emissions) for biofuel use. Regulated emissions used ULEV standards.

	Options	What was addressed
Biofuels	• Agricultural residues • Energy Crops • Corn • Technologies included: – Ethanol production from corn – Ethanol production from cellulosics – Fischer-Tropsch diesel production from agricultural residues or energy crops	• CO_2 emissions from the utilization of the biomass itself or its end product (i.e. the produced fuel) are assumed to be zero (closed-loop carbon cycle) • Carbon dioxide and sulfur dioxide emission are based upon the elemental composition of the fuel and the chain efficiency • For fuel manufacture, emissions within the plant gate are assumed to be from best available control technology. The exception is any vehicles used to move the biomass within the plant gate. These vehicles are assumed to be fueled with petroleum-diesel and have 50/50 emissions associated with a mix of uncontrolled and best available control technology • All grid electricity used for manufacture of the fuel used a grid average mix for emissions estimation • Emissions are included for distribution of the fuel to depot stations and transport to retail stations. Evaporative losses are included for retail marketing of the fuel • Emissions are associated with the biomass portion of the fuel only for blending applications • The vehicle emissions are based on that the vehicle is designed to meet the emission standard (ULEV), regardless of the fuel used. Regulated emissions for each fuel are set by the relevant emission standards – NOx, CO, and nonmethane hydrocarbon standards are set by the 50,000 mile durability ULEV standards for 2001-2006 Model Year for all passenger car's and light-duty trucks (0-3750 lbs LVW) – Particulate matter for compression ignition engines are the 100,000 mile durability standards for new 2001-2003 Model Year TLEV passenger cars and light duty trucks – Methane emissions are calculated from correlations based on the amount on nonmethane hydrocarbon emissions – The effect of ethanol as an oxygenate on emissions in the vehicle was not taken into account

Products were analyzed up to wholesale level. The carbon in the bioproduct was treated as if it were "sequestered" carbon.

	Options	What was addressed
Bioproducts	• Agricultural residues • Energy Crops • Seed oils • Corn • Technologies included: –Fermentation –Oil Splitting of lipids –High temperature pyrolysis –Syngas based processes	• The biobased chemicals value chains were analyzed up to the wholesale level. Thus we did not analyze the potential impacts of changes in product design and usage. The implicit assumption was that the biobased chemicals would have comparable performance. For example, any increases or decreases in the weight of the final products could impact transportation costs of the products, or change energy use in the use of the product. • Also, energy use and emissions impacts associated with the end of the life of the chemical is not considered. We expect that on balance, the impact of this limitation will be neutral, since some bio-based chemicals will perform better, while others will perform less well. Thus carbon incorporated in the product is considered as sequestered • For primary product manufacture, emissions within the plant gate are assumed to be from best available control technology. The exception is any vehicles used to move the biomass within the plant gate. These vehicles are assumed to be fueled with petroleum-diesel and have 50/50 emissions associated with a mix of uncontrolled and best available control technology • All grid electricity used for manufacture of the primary product used a grid average mix for emissions estimation • For fermentation based processes utilizing glucose; we included the comparable emissions to grow and transport the raw corn but did not include the emissions associated with making the glucose from starch in a wet or dry corn mill • Similarly for oil seed based materials; the emissions were assessed for the processing of the seed oil to make the product but did not include the upstream emissions associated with growing the plant, harvesting the seed, transporting the seed, and recovering the raw oil from the seed • Fugitive emissions from biomass stockpiles on the plant site or fugitive emissions associated with unused crop or resource materials were excluded

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Air emissions (in gm/kWh delivered) were evaluated for the biopower options retained in the screening process.

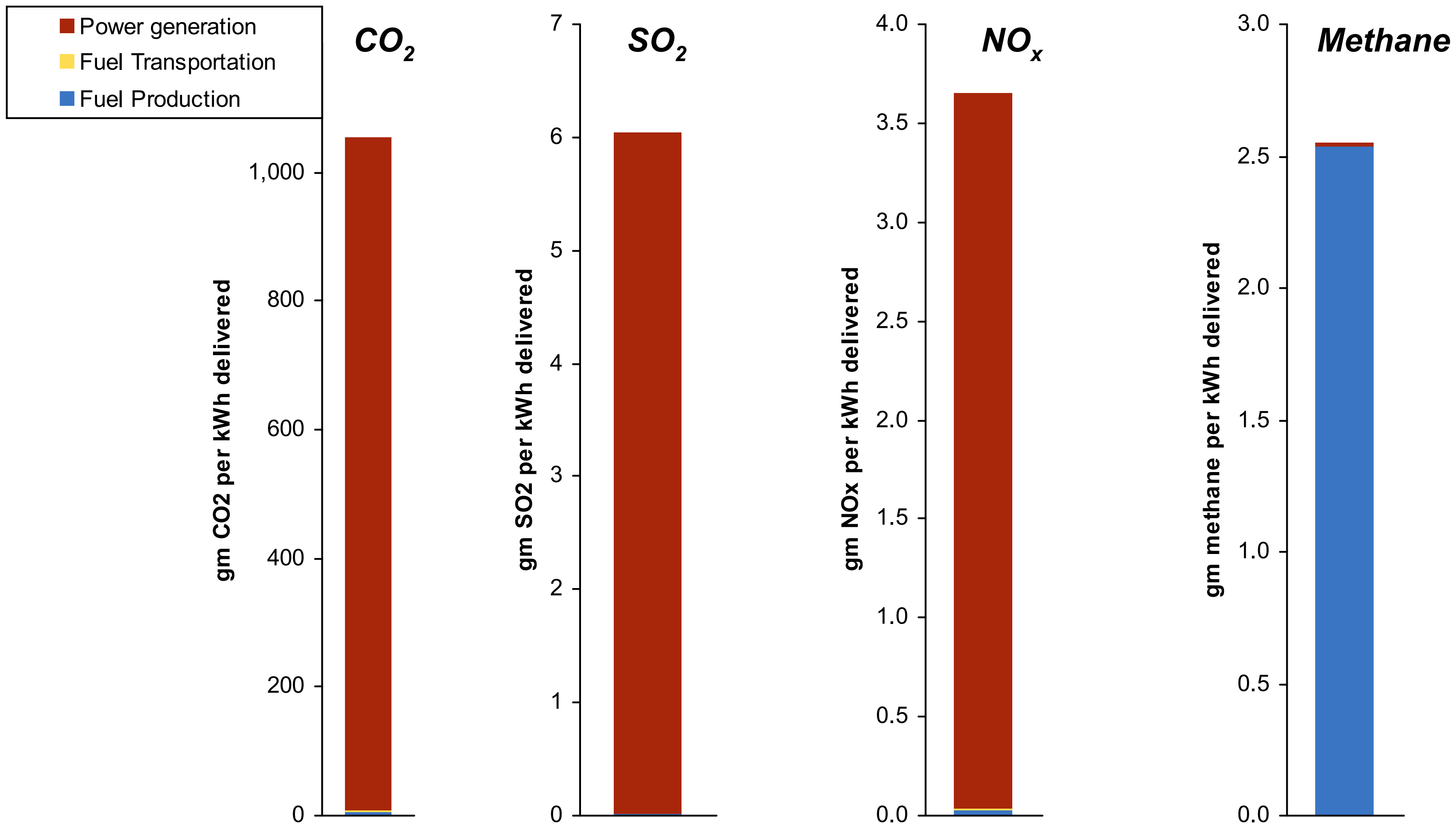
- Greenhouse gas and priority pollutants were evaluated
  - Carbon dioxide (CO_2)
  - Sulfur dioxide (SO_2)
  - Nitrogen oxides (NO_x)
  - Methane (CH_4)
  - Non-methane hydrocarbons (NMHC)
  - Particulate matter (PM)
  - Carbon monoxide (CO)
- CO_2 emissions from the biomass power generation step of the fuel chain were assumed to be zero (closed-loop carbon cycle)
  - CO_2 emissions occur when other fuels and materials (e.g., chemical fertilizers) are used to grow, harvest, transport and process the biomass
- Results from the analyses can be found in tables in the Data Volume

The nature of the biopower opportunities required the development of several baselines in order to compare emissions benefits and impacts.

Baseline	Applicable Biopower Options	Comments
Existing Coal Power Plants	• Direct combustion – co-firing biomass Rankine cycle (with coal) • Gasification – co-firing biomass Rankine cycle (with coal)	• These biomass options have the specific impact of displacing existing coal capacity • Baseline emissions data developed from DOE/EIA data as reported in the *Electric Power Annual 1998*
New Gas-fired Gas Turbine Combined Cycle Power Plants (GTCC)	• Gasification – co-firing biomass GTCC (with natural gas) • RDF Gasification • All biogas combustion options • Gasification of process wastes	• These biomass options compete with other new capacity, which is expected to be predominantly natural gas fired GTCC • Baseline emissions data developed by Arthur D. Little for new, state-of-the-art facilities

With the exception of methane and NMHC, most emissions from conventional coal plants occur during the actual electricity generation step.

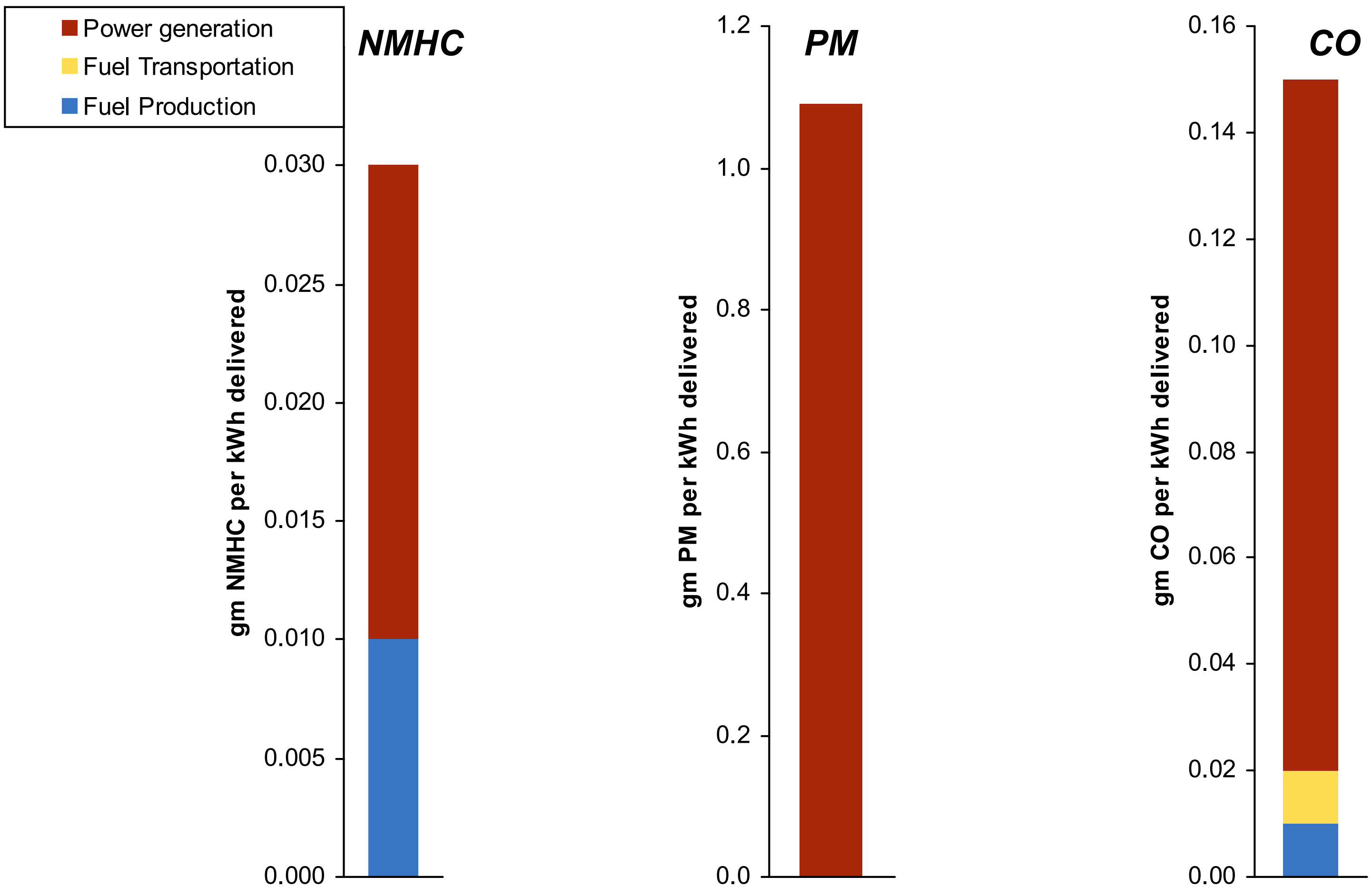
Full Fuel Chain Air Emissions of Coal Rankine, All in Grams per kWh Delivered



1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent.

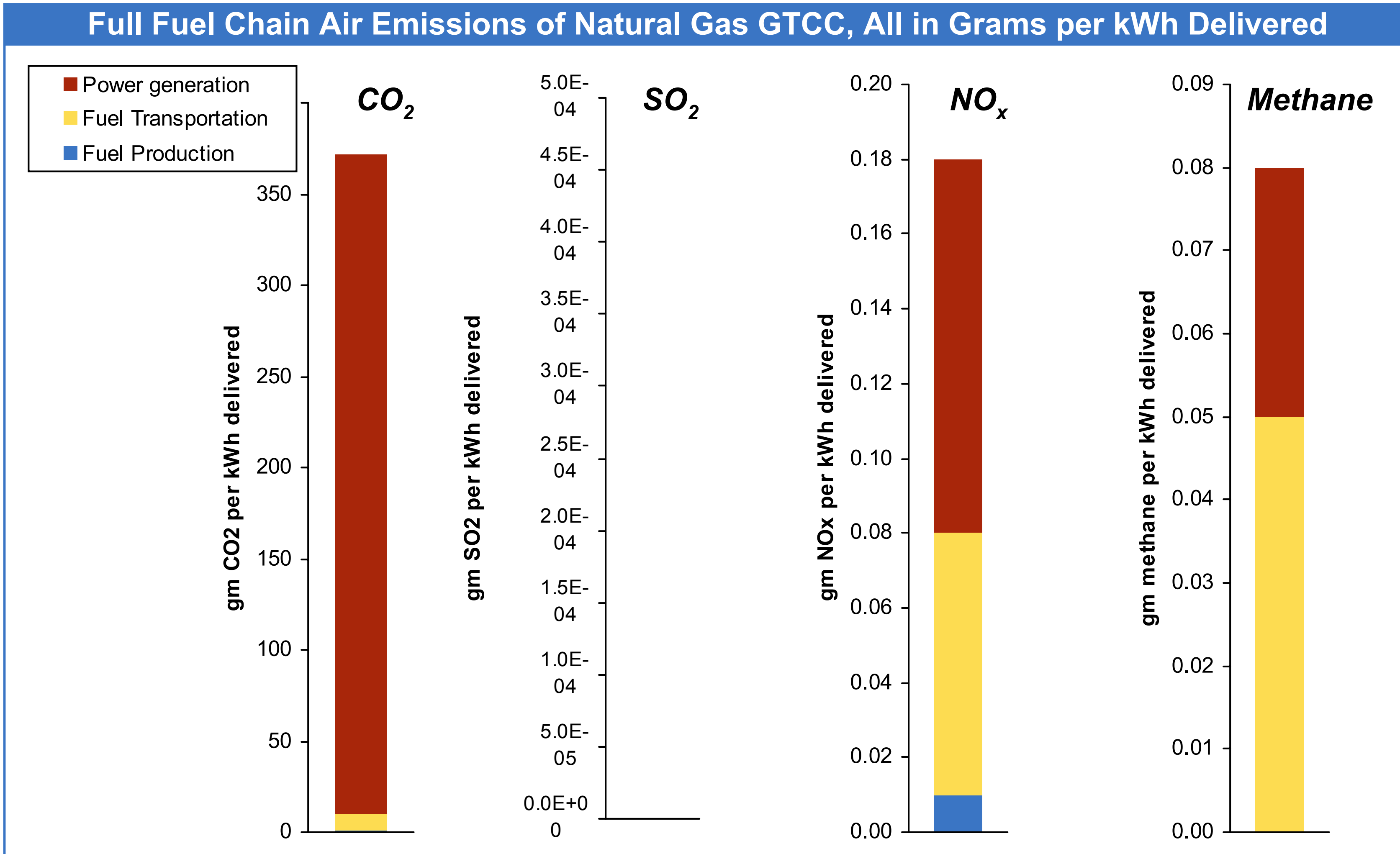
With the exception of methane and NMHC, most emissions from conventional coal plants occur during the actual electricity generation step.

Full Fuel Chain Air Emissions of Coal Rankine, All in Grams per kWh Delivered



1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent.

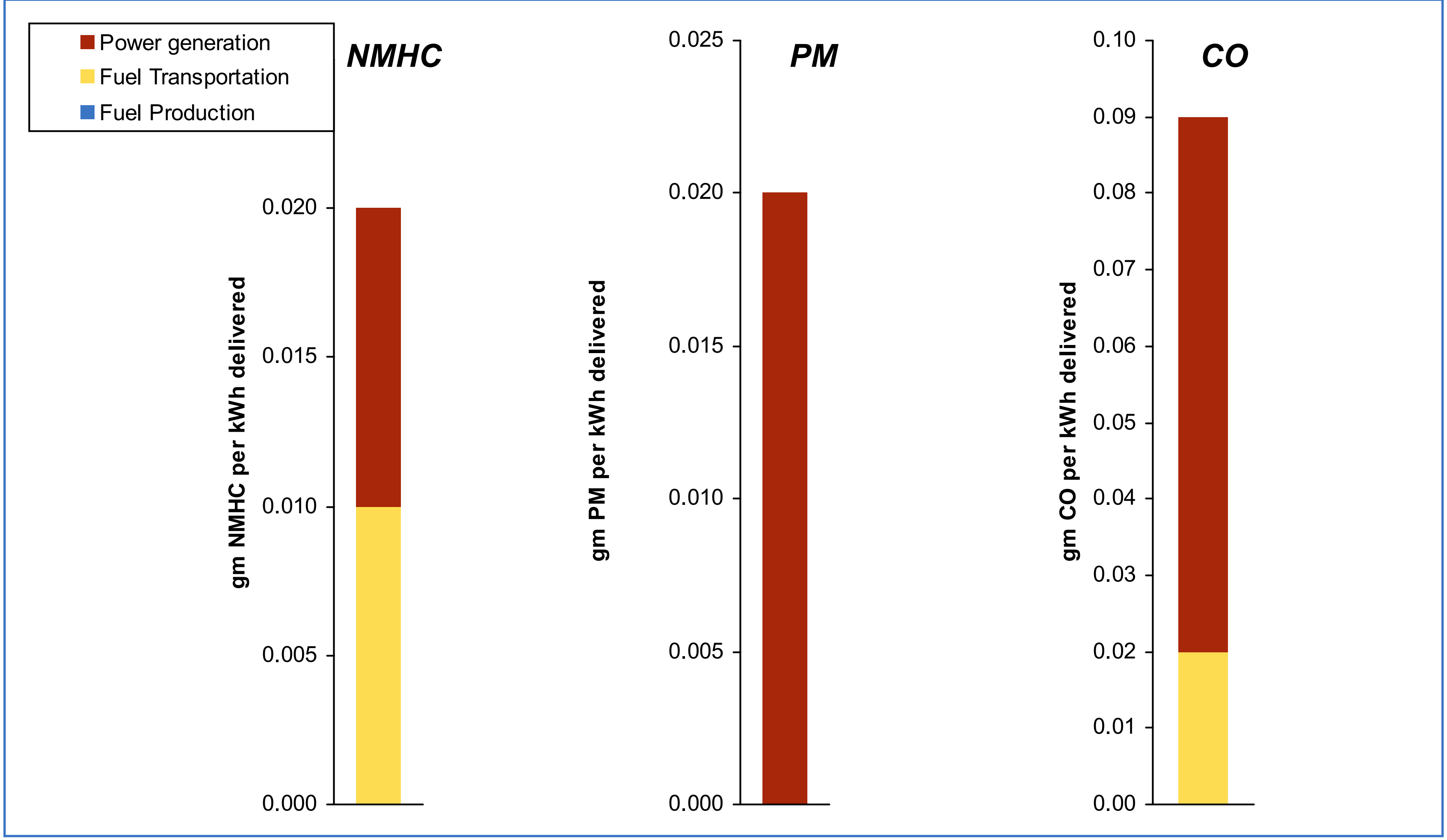
The emissions from Natural Gas GTCC are generally distributed between the power generation and fuel transportation steps.



1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent.

The emissions from Natural Gas GTCC are generally distributed between the power generation and fuel transportation steps.

Full Fuel Chain Air Emissions of Natural Gas GTCC, All in Grams per kWh Delivered



1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent.

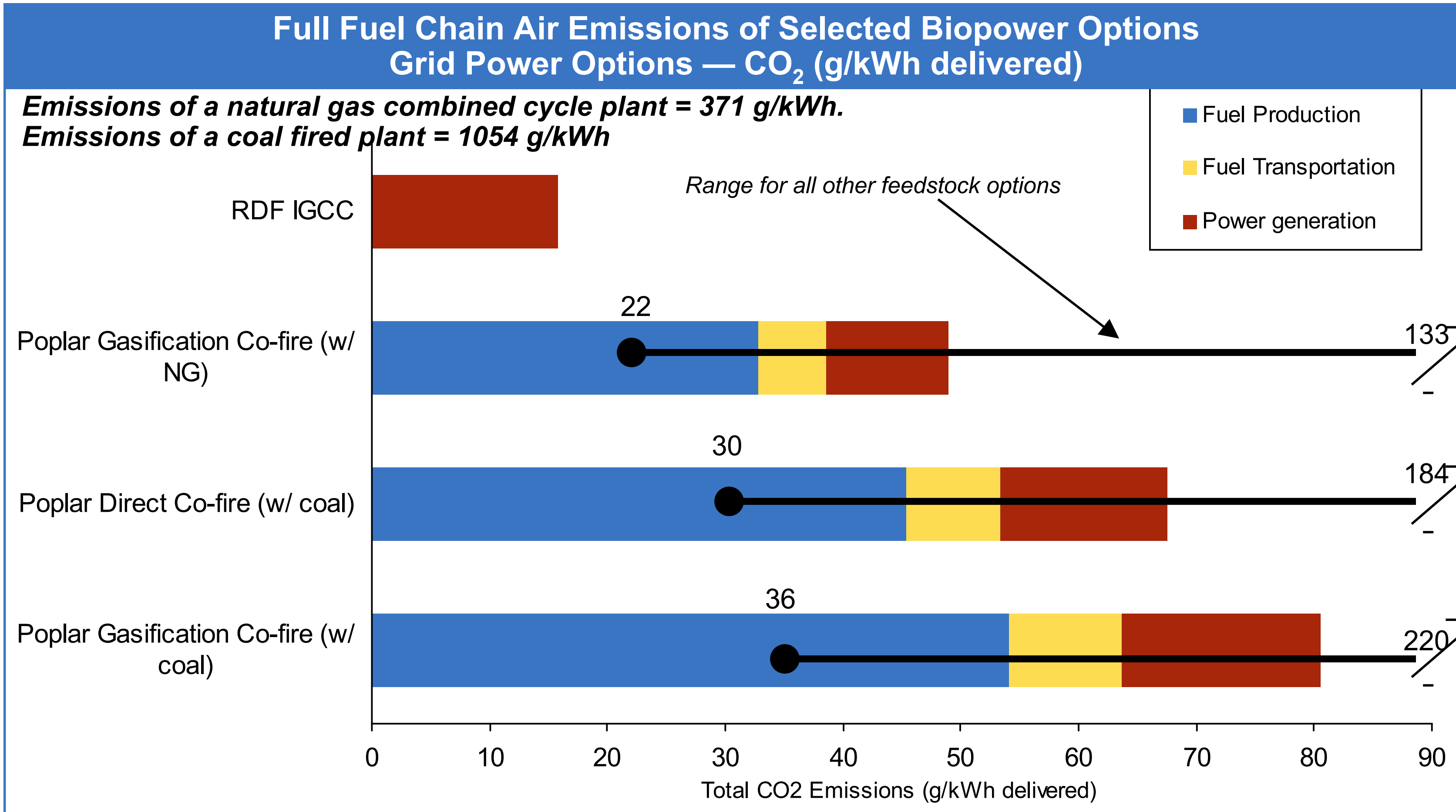
Relative to the appropriate competitive power option, biopower typically offers the greatest emissions benefits for CO_2 and SO_2.

- In all cases CO_2 reductions (per kWh) are significant, ranging from 65-100%
- Except when compared to natural gas GTCC, biomass power results in significant SO_2 reductions (80-97%)
  - Biomass is generally much lower in sulfur than coal
  - In other processes (e.g. gasification) sulfur removal to very high levels is possible
- NO_x benefits are more mixed, and generally are technology (versus fuel) dependent
  - Natural gas GTCC technology sets a very high standard for NOx (Low generation levels),
  - Biogas-fired GTCCs are expected to have similar NOx benefits depending upon the nitrogen content of the biogas
  - Biomass co-firing with coal has the potential for significant NOx benefits (e.g., 20% overall reduction for 10% co-firing)
  - Reciprocating engines produce levels of NOx comparable to or greater than the grid average unless special control equipment is used
- Emissions of CH_4, non-methane hydrocarbons and carbon monoxide, are generally unaffected by the use of biomass as a fuel with the exception of coal based power
  - Emissions of CH_4 are reduced with biomass co-firing with coal by avoiding coal production emissions of methane
- Advanced biopower conversion technologies should produce particulate matter (PM) reductions
  - All technologies that convert landfill gas or other biogases produce less PM than the grid average
  - Co-firing biomass options do not produce PM reductions
- The solid waste and water effluent impact are expected to be moderate and manageable
  - Most biomass is low in ash and in most cases, the ash is non-toxic and can actually have value as fertilizer
  - Water effluents can contain suspended solids and biological oxygen demands but toxicity is not usually a serious concern

All biopower options produce significant (65-80%) reductions in CO_2 emissions, per kWh delivered.

Assumptions and Methodology	• CO_2 emissions from the utilization of the biomass itself are assumed to be zero (closed-loop carbon cycle) – CO_2 emissions occur when other fuels and materials (e.g., chemical fertilizers, seeds, pesticides) are used to grow, harvest, transport and process the biomass • Grid-sited options include the effects of transmission & distribution energy losses (i.e., results are shown per kWh delivered) • Biogas (including landfill, sewage, and digester gas) is generated and used where it is produced so there is no energy use (and therefore no CO_2 emissions) associated with biomass production and transport • For RDF, the emissions associated with collection and processing are not included as these would need to be done regardless of the use of RDF for fuel – The non-biomass portion of RDF is also excluded
Comments	• For agricultural residues and energy crops, many biomass fuel types are possible. Poplar is used here as an example of a woody biomass resource that would be grown as an energy crop • For the remaining solid biomass feedstocks (e.g., switchgrass, corn stover), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for poplar
Conclusions	• Biopower CO_2 emissions are associated mainly with feedstock production (where applicable) – This is also generally true for the feedstocks for which only the totals are shown • Biomass transport and handling are secondary sources of CO_2 emissions • All grid-based biopower options produce significant (>65%) reductions in CO_2 emissions, per kWh delivered – The lowest levels of reductions are relative to natural gas GTCC power plants, but only for the feedstocks with high production and transport related energy requirements • Onsite use of biomass produces even greater CO_2 benefits, per kWh – Reductions of 93-97% are possible, relative to a high efficiency gas-fired GTCC

Biopower CO_2 emissions are associated mainly with biomass production and secondarily with biomass handling on-site.

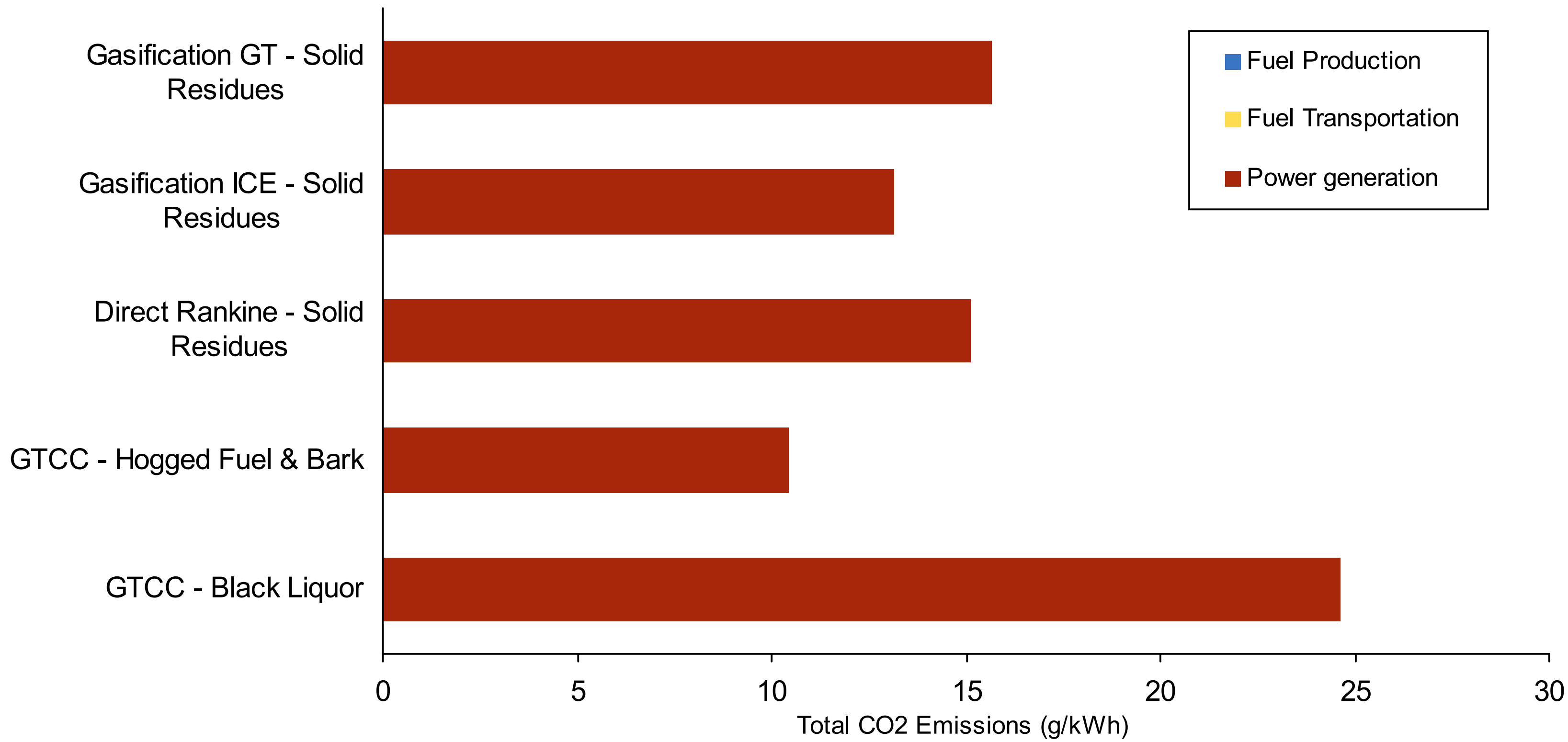


1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent.
2. Landfill gas options are not shown because new emissions of CO_2 are zero.
3. The biomass feedstocks used for gasification co-firing with natural gas were corn stover, wheat straw, woody biomass (poplar), and switchgrass; the range shown reflects the full chains using these other feedstocks

As would be expected, all biopower options result in significant CO_2 reductions over the competing conventional options.

Full Fuel Chain Air Emissions of Selected Biopower Options
On Site Options — CO_2 (g/kWh produced)

Emissions of a natural gas combined cycle plant = 371 g/kWh



Process residues are generated and used onsite, so there are zero emissions associated with "production" or transportation.

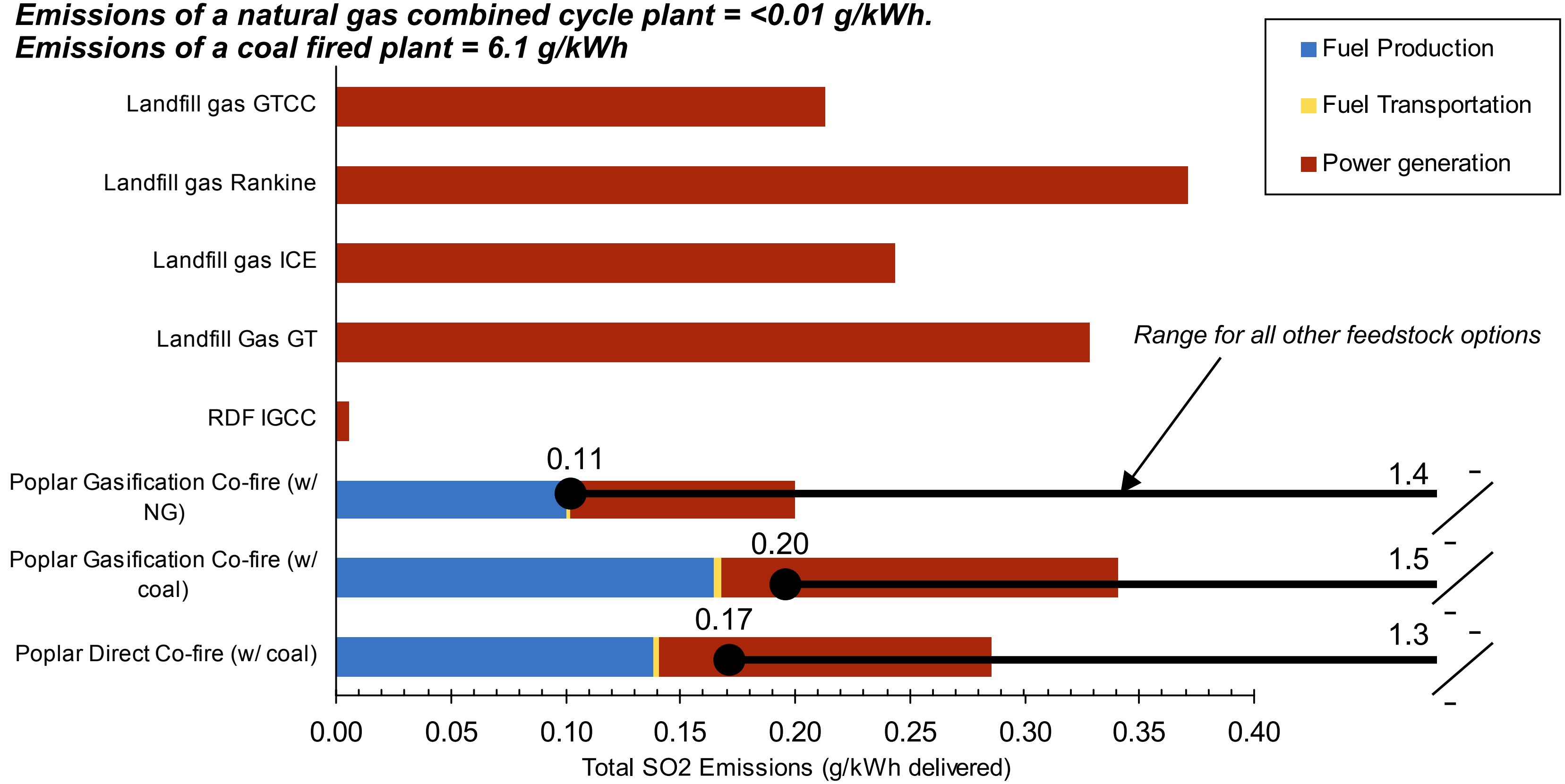
Biopower produces significant reduction in SO_2 emissions relative to coal, but not to natural gas, a virtually sulfur-free fuel.

Assumptions and Methodology	• SO_2 emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers, pesticides), which are used to grow, harvest, transport and process the biomass • Grid-sited options include the effects of transmission & distribution energy losses (i.e., results are shown per kWh delivered) • Biogas (including landfill, sewage and digester gas) is generated and used where it is produced so there is no energy use (and therefore no SO_2 emissions) associated with biomass production and transport • For RDF, the emissions associated with collection and processing are not included as these would need to be done regardless of the use of RDF for fuel
Comments	• For agricultural residues and energy crops, many biomass fuel types are possible. Poplar is used here as an example of a woody biomass resource that would be grown as an energy crop. – For the remaining feedstocks (e.g., switchgrass, corn stover, wheat straw), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for poplar • Most biomass is relatively low in sulfur and therefore no controls are used. For selected feedstocks that are higher in sulfur, such as black liquor, sulfur control technology is used
Conclusions	• While significantly lower than coal SO_2 emissions, biopower options do not offer superior SO_2 emission to a natural gas GTCC, since natural gas is essentially a sulfur free fuel • For landfill gas, all emissions are associated with the power generation step • For grid power using dedicated woody biomass feedstocks, emissions are split roughly equally between biomass production and power generation • Biomass transport and handling add little SO_2 emissions • Co-firing with coal options produce significant (75-97%) reductions in SO_2 emissions, per kWh produced • Emissions of SO_2 for onsite power options vary from about 0.04 g/kWh to 0.50 g/kWh, depending on the fuel type and whether or not emissions control is used – Only the lowest levels of SO_2 emissions, achievable only with sulfur control technology, approach the levels of a natural gas GTCC • Fuel cell emissions of SO_2 are effectively zero, as the fuel must be scrubbed free of sulfur to avoid poisoning of the fuel cell stack

SO_2 emissions from biopower depend strongly on the type of feedstock and whether or not emissions control is used (as it is with RDF IGCC).

Full Fuel Chain Air Emissions of Selected Biopower Options
Grid Power Options — SO_2 (g/kWh delivered)

Emissions of a natural gas combined cycle plant = <0.01 g/kWh.
Emissions of a coal fired plant = 6.1 g/kWh

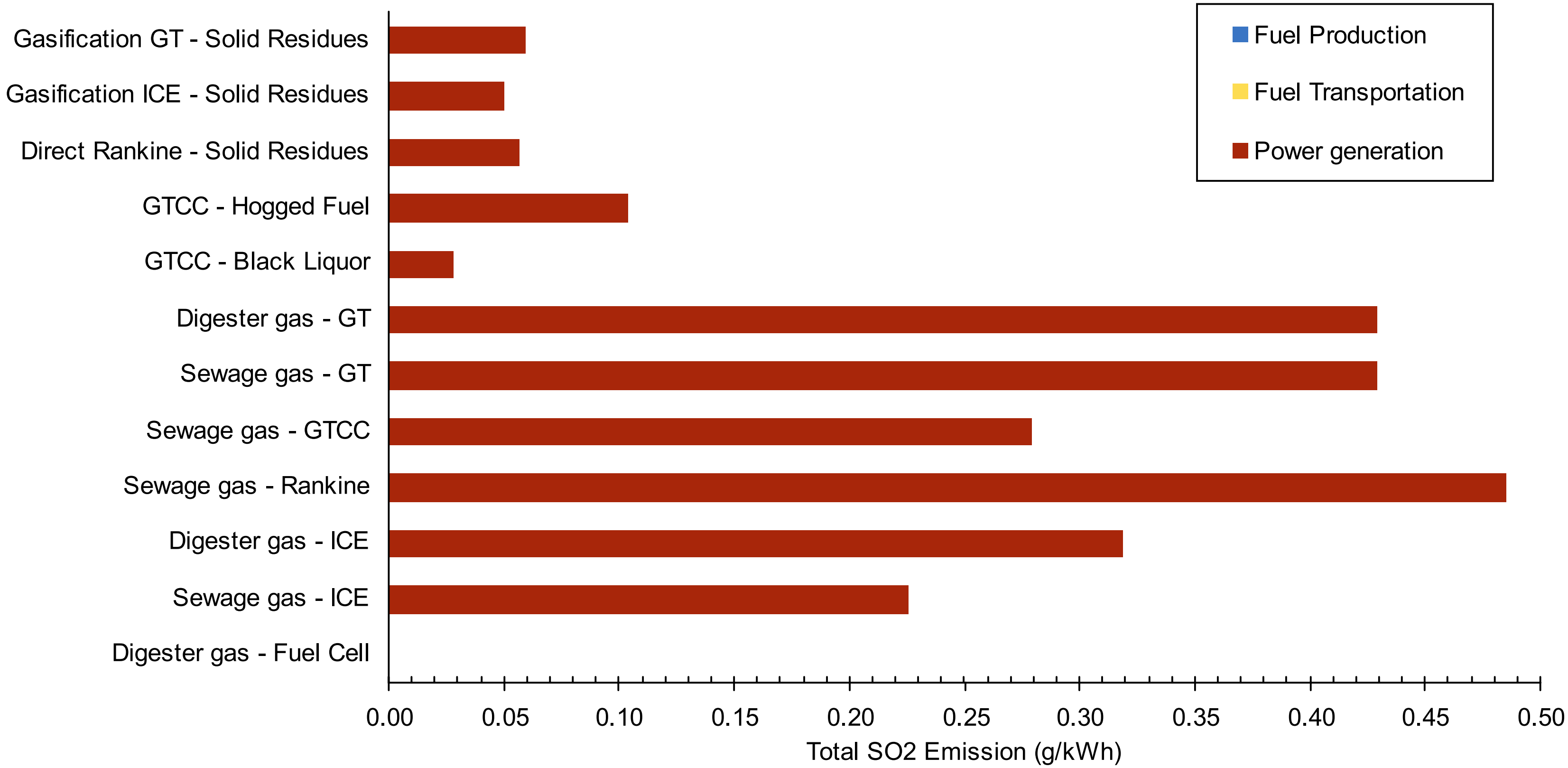


1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent.
2. The biomass feedstocks used for co-firing options were corn stover, wheat straw, woody biomass (poplar), and switchgrass; the range shown reflects the full chains using these other feedstocks

Biogases generally have higher sulfur content than solid biomass residues.

Full Fuel Chain Air Emissions of Selected Biopower Options
On Site Power Options — SO_2 (g/kWh produced)

Emissions of a natural gas combined cycle plant = <0.01 g/kWh.



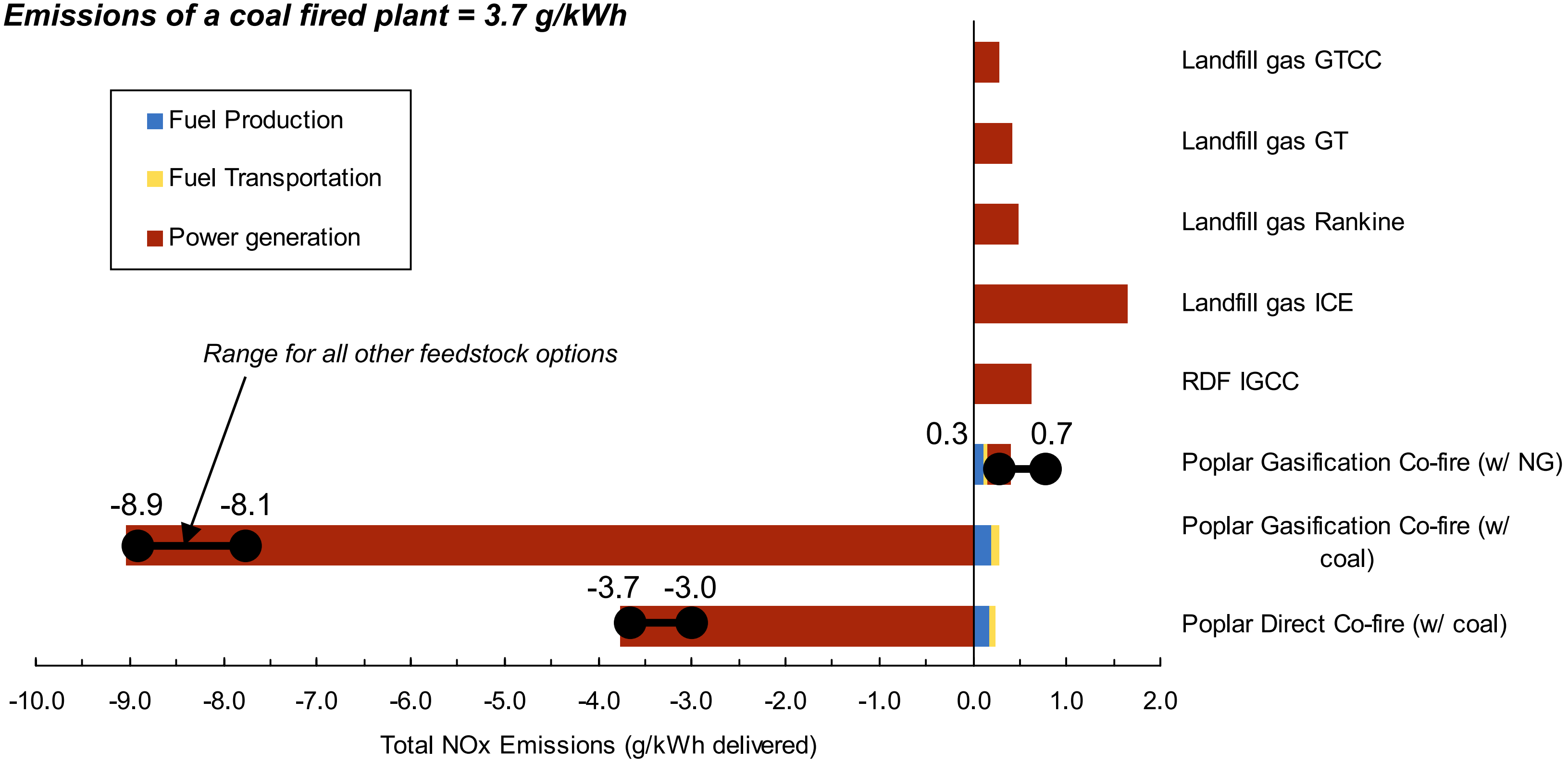
Biomass co-firing with coal yields substantial NOx savings, but most other options are not better than a natural gas-fired GTCC.

Assumptions and Methodology	• NOx emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass • Grid-sited options include the effects of transmission & distribution energy losses (i.e., results are shown per kWh delivered) • Biogas (including landfill, sewage, and digester gas) is generated and used where it is produced so there is no energy use (and therefore no NOx emissions) associated with biomass production and transport • For biomass co-firing with coal, the co-firing reduces the NOx emissions of the entire plant – all of these reductions are credited to the biomass • For RDF, the emissions associated with collection and processing are not included as these would need to be done regardless of the use of RDF for fuel – The non-biomass portion of RDF is also excluded
Comments	• For agricultural residues & energy crops, many biomass fuel types are possible. Poplar is used here as an example of a woody biomass resource that would be grown as an energy crop – For the remaining feedstocks (e.g., switchgrass, corn stover, wheat straw), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for poplar • NOx emissions estimates are consistent with typical controls (e.g., dry low NOx combustion for gas turbines, lean burn technology for internal combustion engines) • For co-firing with coal it is assumed that each percentage point of biomass co-firing results in a 2 percentage point decrease in overall NOx for direct firing and a 4 percentage point decrease for gasification co-firing (the latter is consistent with the use of the biomass as a reburn technology)
Conclusions	• Biomass-only options do not result in lower NOx emissions relative to the natural gas GTCC baseline • However, biomass co-firing with coal has the potential to reduce NOx emissions for the entire plant – Because these reduction are associated strictly with the act of co-firing, the result is negative NOx emissions for the biomass, that are significant per kWh of biomass power produced • The large natural gas GTCC baseline has the lowest emissions of NOx per BTU fuel consumed plus the highest efficiency, and therefore has the lowest per kWh emissions • internal combustion engines typically have higher NOx emissions than other options, and at small scales, additional exhaust cleanup technology is often not used (as has been modeled here), resulting in the highest NOx emissions per kWh produced • The results are similar for grid-sited and onsite power options • Fuel cell emissions of NOx are effectively zero, as NOx is a product of high-temperature combustion, which is absent in the fuel cell

In biomass co-firing with coal, the use of biomass has the potential to reduce considerably total plant NOx emissions.

Full Fuel Chain Air Emissions of Selected Biopower Options
Grid Power— NOx (g/kWh delivered)

Emissions of a natural gas combined cycle plant = 0.2 g/kWh.
Emissions of a coal fired plant = 3.7 g/kWh

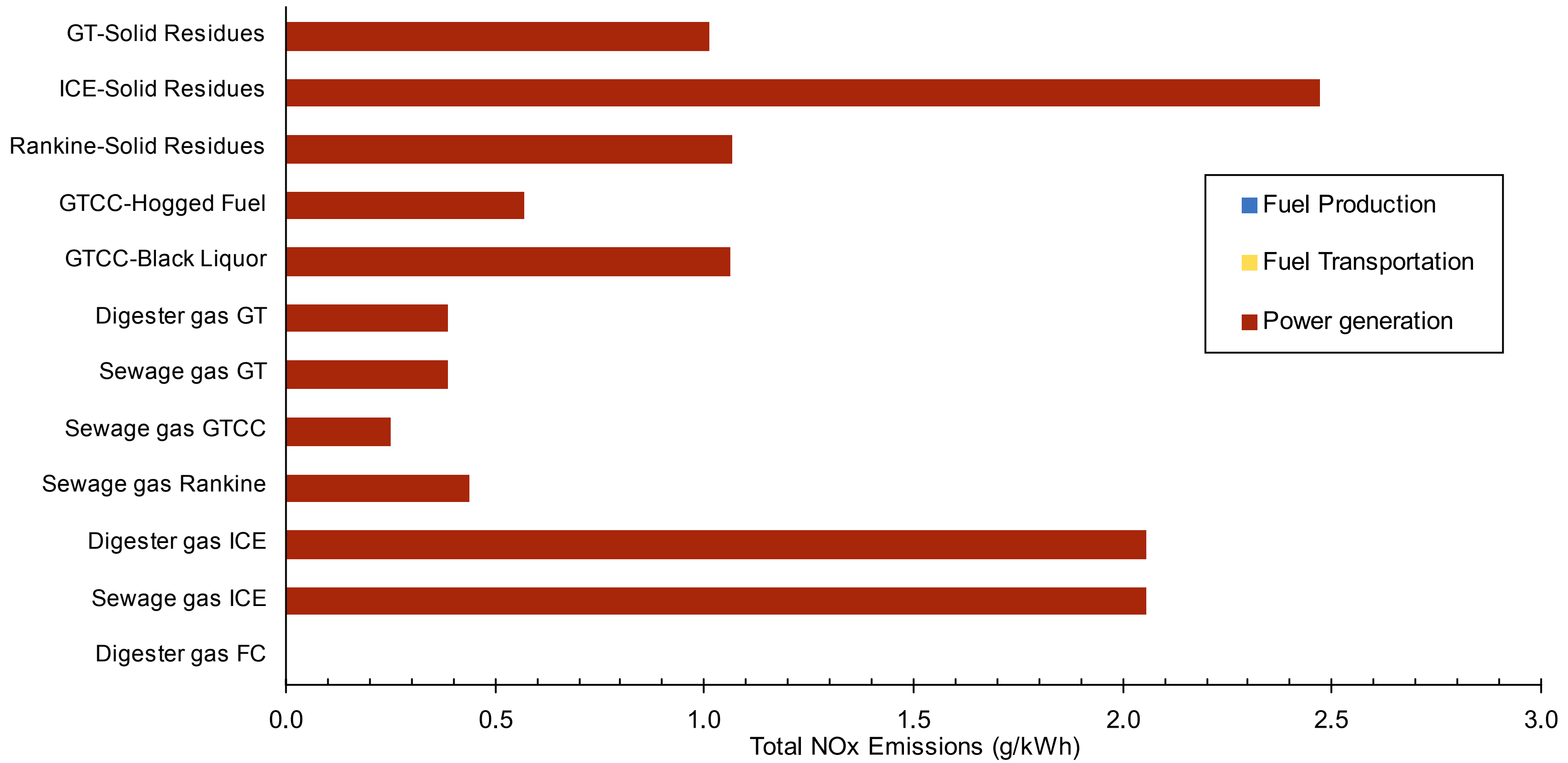


1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent.
2. The feedstocks used for the co-firing options were corn stover, wheat straw, woody biomass (poplar), and switchgrass; the range shown reflects the full chains using these other feedstocks

For onsite power options, an advantage for NOx does seem to be present compared to natural gas combined cycle technology.

Full Fuel Chain Air Emissions of Selected Biopower Options On Site Power — NOx (g/kWh produced)

Emissions of a natural gas combined cycle plant = 0.2 g/kWh.



Unlike CO_2, SO_2 and NOx, methane reduction is not as major an environmental driver for biomass power although reductions are accomplished.

Assumptions and Methodology

- Methane emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass
- Grid-sited options include the effects of transmission & distribution energy losses (i.e., results are shown per kWh delivered)
- Biogas (including landfill, sewage, and digester gas) is generated and used where it is produced so there is no energy use (and therefore no methane emissions) associated with biomass production and transport
  - Fugitive CH_4 emissions that would have occurred regardless of the end use for the biogas were also excluded
- For biomass co-firing with coal, the co-firing is assumed to have no effect on overall methane emissions not counting methane emission reductions from decreased use of coal
- For RDF, the emissions associated with collection and processing are not included as these would need to be done regardless of the use of RDF for fuel. (The non-biomass portion of RDF is also excluded)

Comments

- For agricultural residues & energy crops, many biomass fuel types are possible. Poplar is used here as an example of a woody biomass resource that would be grown as an energy crop
  - For the remaining feedstocks (e.g., switchgrass, corn stover, wheat straw), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for poplar
- Methane emissions are generally uncontrolled emissions consistent with current good practices for combustion (e.g., dry low NOx combustion for gas turbines, lean burn technology for internal combustion engines)
- For co-firing with coal it is assumed that biopower methane emissions are the same per BTU of fuel consumed as for the baseline coal plant, so that differences in emissions per kWh are related to differences in efficiency

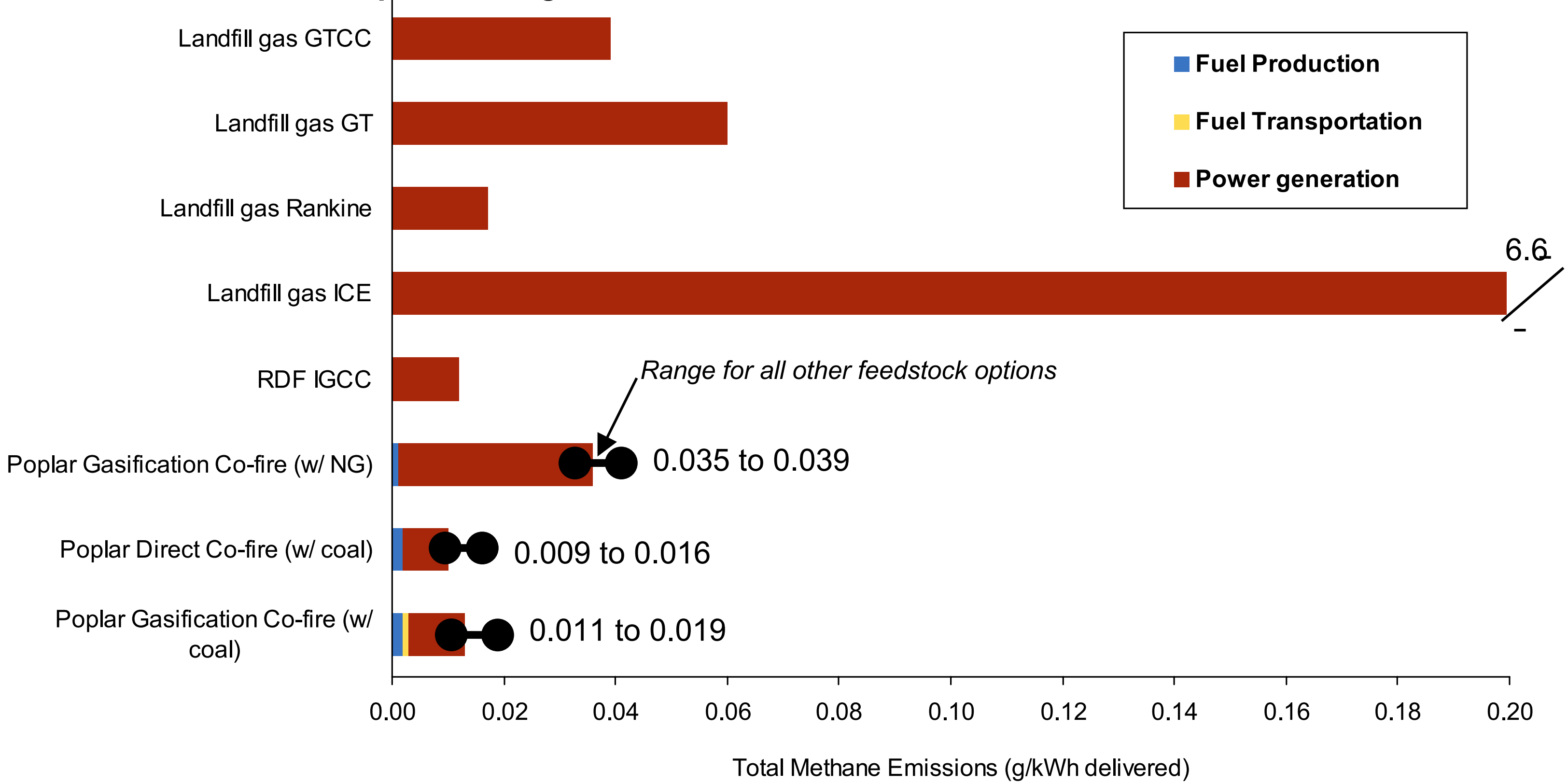
Conclusions

- With the exception of the internal combustion engine, biogas options generally should result in modest methane emissions reduction relative to the baseline natural gas GTCC plant
  - Internal combustion engine emissions could be lower than that shown here, if, for example, catalytic converters are used to oxidize unburned hydrocarbons in the exhaust
- Because coal plants have inherently low emissions of methane, biomass co-firing with coal produces similarly low levels of methane emissions; when compared to full chain coal emissions; there is methane savings with co-firing with coal
- The results are similar for grid-sited and onsite power options
- Biomass-only gasification options are expected to produce less methane emissions than natural gas power plants because methane typically constitutes approximately 10-20% by volume of the fuel gas
- Fuel cell emissions of methane are effectively zero, as virtually all the methane is converted to hydrogen
  - Any residual methane is then burned in a low-emissions burner to generate heat to run the fuel processor

Grid-sited biopower methane emissions are mainly an issue for biogas options such as landfill gas, particularly internal combustion engines.

Full Fuel Chain Air Emissions of Selected Biopower Options
Grid Power — CH_4 (g/kWh delivered)

Emissions of a natural gas combined cycle plant = 0.079g/kWh.
Emissions of a coal fired plant = 2.6 g/kWh

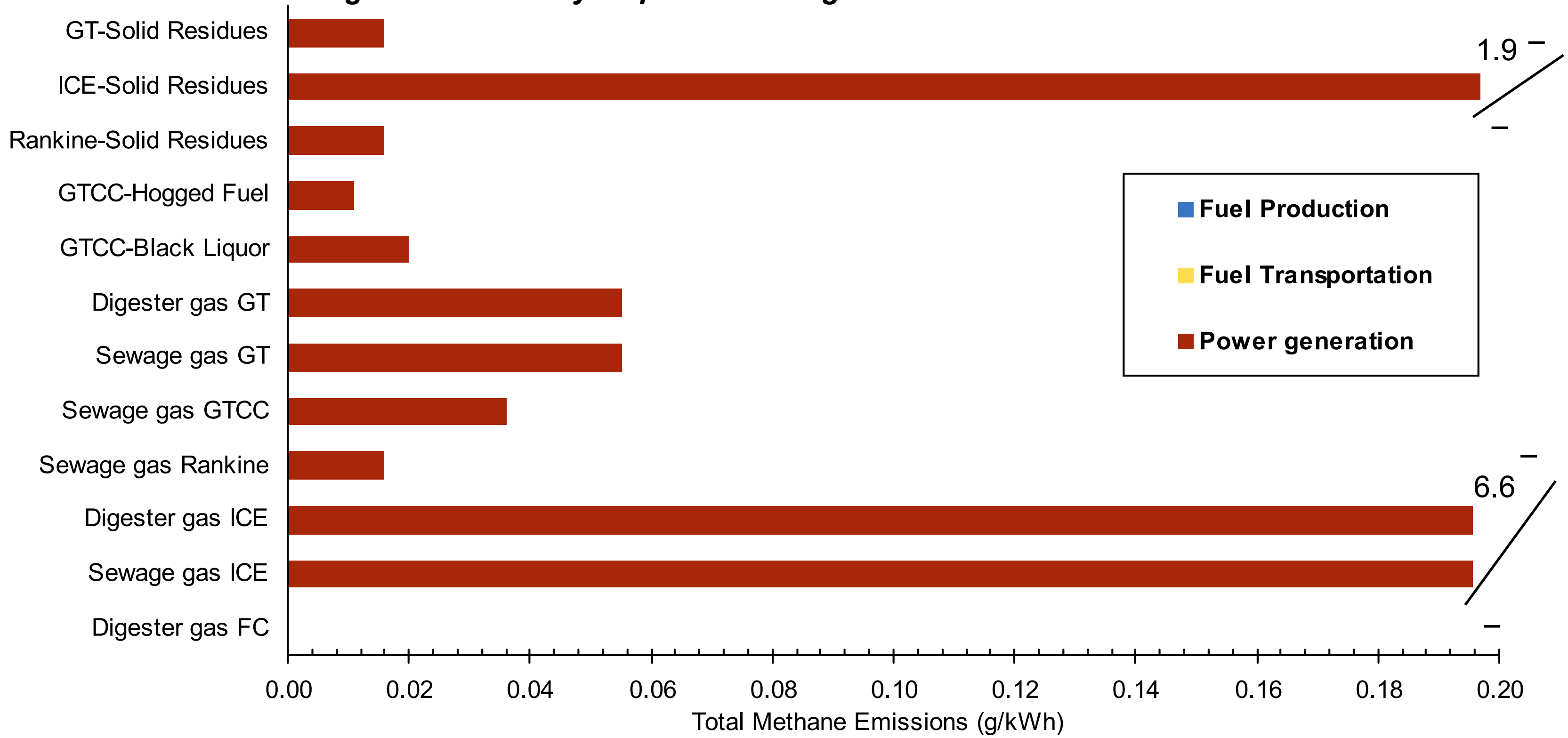


1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent.
2. The feedstocks used for the co-firing options were corn stover, wheat straw, woody biomass (poplar), and switchgrass; the range shown reflects the full chains using these other feedstocks

Onsite biopower methane emissions are mainly an issue for biogas options and options utilizing internal combustion engines.

Full Fuel Chain Air Emissions of Selected Biopower Options On Site Power — CH_4 (g/kWh produced)

Emissions of a natural gas combined cycle plant = 0.079g/kWh.



The situation with NMHCs is similar to that for methane – biomass does not yield significant reductions over the baseline.

Assumptions and Methodology	• NMHC emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass
	• Grid-sited options include the effects of transmission & distribution energy losses (i.e., results are shown per kWh delivered)
	• Biogas (including landfill, sewage, and digester gas) is generated and used where it is produced so there is no energy use (and therefore no NMHC emissions) associated with biomass production and transport
	  – Fugitive emissions that would have occurred regardless of the end use for the biogas were also excluded
	• For biomass co-firing with coal, the co-firing is assumed to have no effect on overall NMHC emissions
	• For RDF, the emissions associated with collection and processing are not included as these would need to be done regardless of the use of RDF for fuel
	  – The non-biomass portion of RDF is also excluded

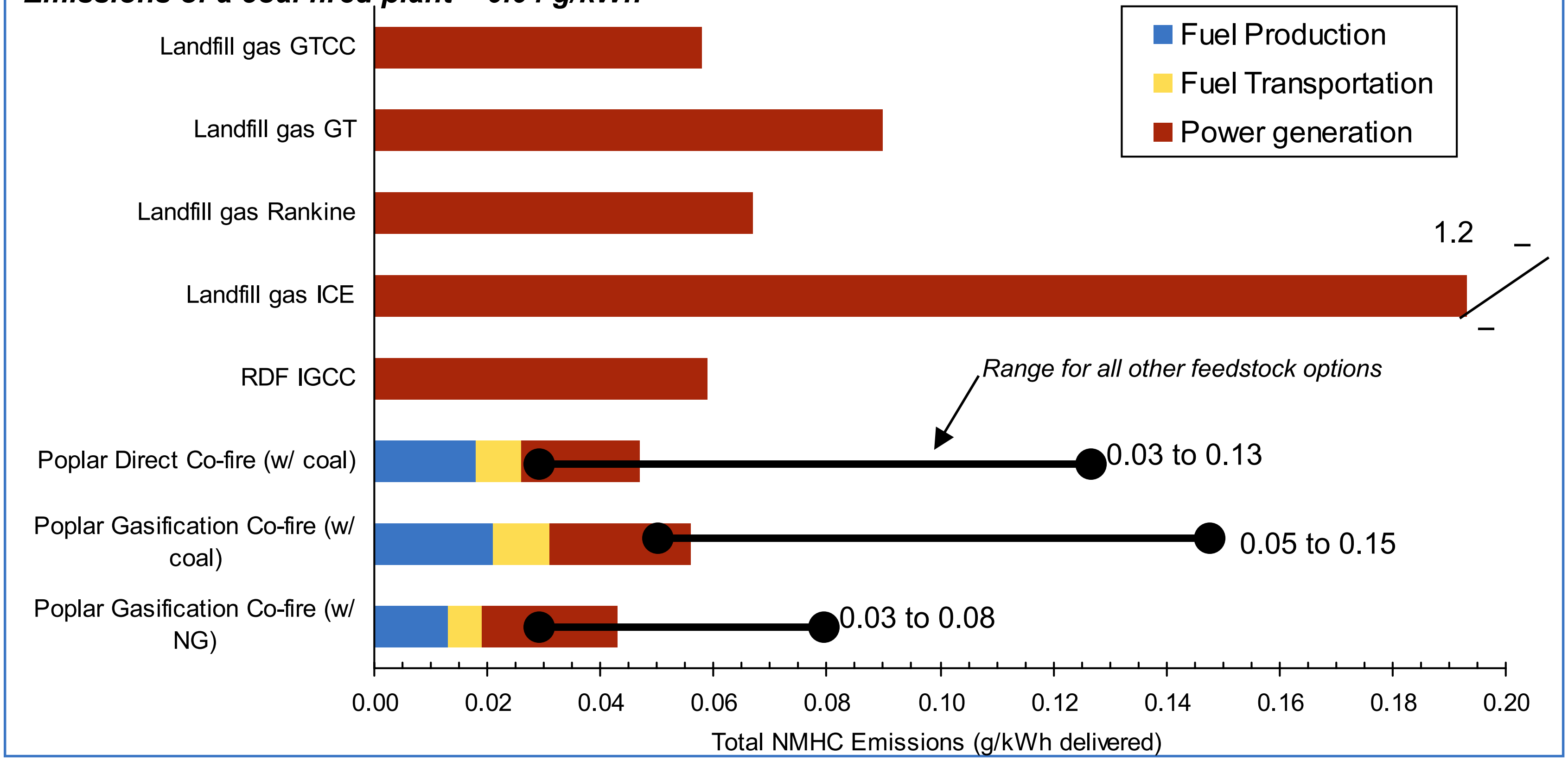
Comments	• For agricultural residues & energy crops, many biomass fuel types are possible. Poplar is used here as an example of a woody biomass resource that would be grown as an energy crop • For the remaining feedstocks (e.g., switchgrass, corn stover, wheat straw), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for poplar • NMHC emissions are generally uncontrolled emissions consistent with current good practices for combustion (e.g., dry low NOx combustion for gas turbines, lean burn technology for internal combustion engines) • For co-firing with coal it is assumed that biopower NMHC emissions are the same per BTU of fuel consumed as for the baseline coal plant, so that differences in emissions per kWh are related to differences in efficiency

Conclusions	• With the exception of the internal combustion engine, biogas options generally result in modest increases in NMHC emissions relative to the baseline natural gas GTCC plant
	  – internal combustion engine emissions could be lower than that shown here, if, for example, catalytic converters are used to oxidize unburned hydrocarbons in the exhaust
	• Because coal plants have inherently low emissions of NMHCs, biomass co-firing with coal produces similarly low levels of NMHC emissions
	• The results are similar for grid-sited and onsite power options
	• Biomass-only gasification options are expected to produce higher NMHC emissions than natural gas power plants because NMHCs can be found in higher levels in fuel gas than natural gas. The lower efficiencies also result in higher per kWh emissions
	• Fuel cell emissions of NMHCs are effectively zero, as virtually all the C2 and C3 NMHCs are converted to hydrogen
	  – Any residual NMHCs are then burned in a low-emissions burner to generated heat to run the fuel processor

In cases where upstream steps are non-zero, they can be as important as the power generation step

Full Fuel Chain Air Emissions of Selected Biopower Options Grid Power — NMHCs (g/kWh delivered)

Emissions of a natural gas combined cycle plant = 0.013 g/kWh.
Emissions of a coal fired plant = 0.04 g/kWh

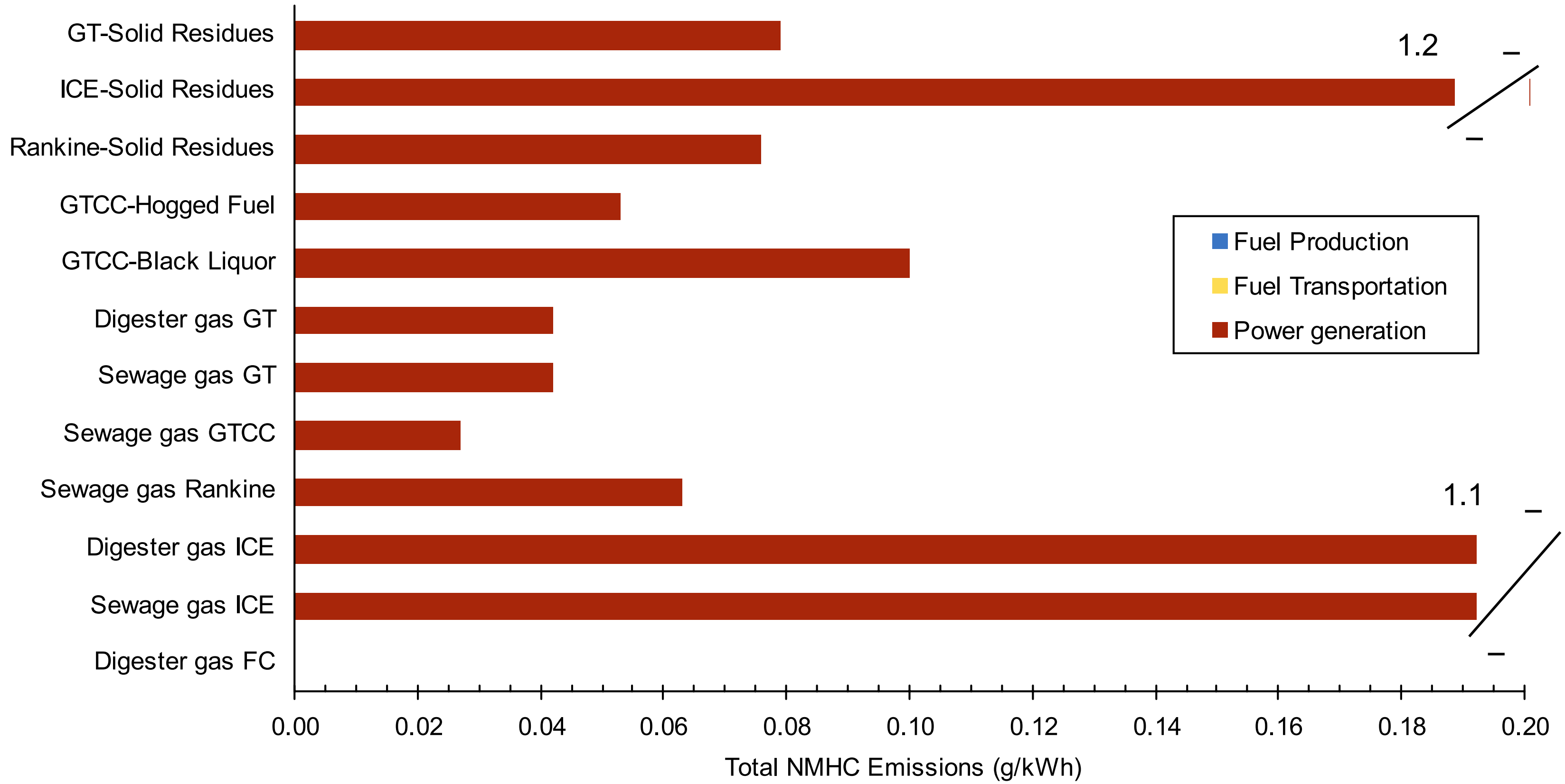


1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent.
2. The feedstocks used for the co-firing options were corn stover, wheat straw, woody biomass (poplar), and switchgrass; the range shown reflects the full chains using these other feedstocks

For most onsite options, biomass does not offer benefits compared to natural gas combined cycle technology.

Full Fuel Chain Air Emissions of Selected Biopower Options
On Site Power — NMHCs (g/kWh produced)

Emissions of a natural gas combined cycle plant = 0.013 g/kWh.



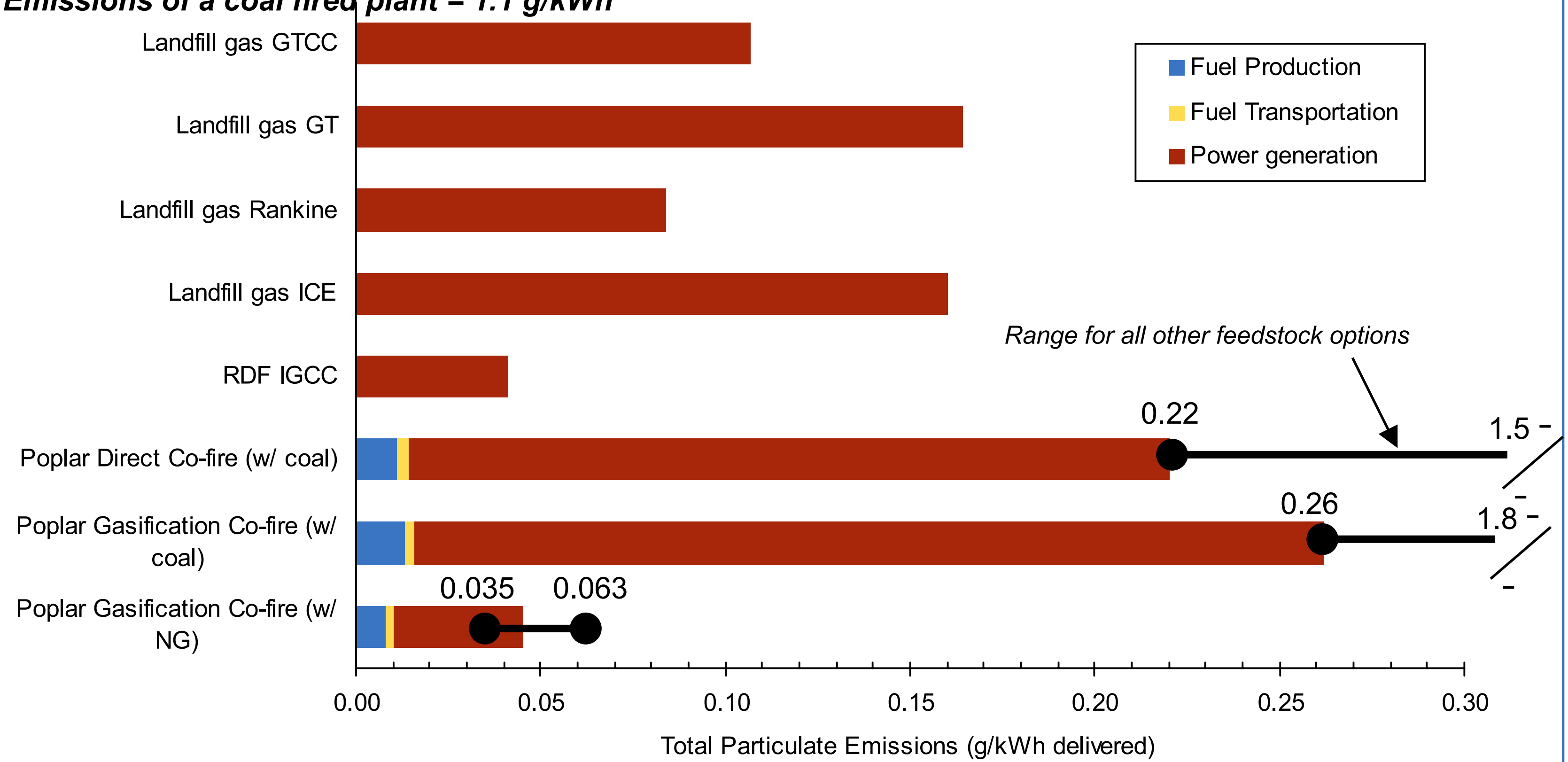
Biomass co-firing with coal can produce some PM reductions, but generally, biopower does not result in significant PM savings.

Assumptions and Methodology	• PM emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass • Grid-sited options include the effects of transmission & distribution energy losses (i.e., results are shown per kWh delivered) • Biogas (including landfill, sewage, and digester gas) is generated and used where it is produced so there is no energy use (and therefore no PM emissions) associated with biomass production and transport – Fugitive emissions that would have occurred regardless of the end use for the biogas were also excluded • For biomass co-firing with coal, the co-firing is assumed to reduce PM emissions based on the relative ash content of biomass and coal • For RDF, the emissions associated with collection and processing are not included as these would need to be done regardless of the use of RDF for fuel – The non-biomass portion of RDF is also excluded
Comments	• For agricultural residues & energy crops, many biomass fuel types are possible. Poplar is used here as an example of a woody biomass resource that would be grown as an energy crop – For the remaining feedstocks (e.g., switchgrass, corn stover, wheat straw), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for poplar • PM emissions are generally controlled emissions consistent with current good practices (e.g., ESPs)
Conclusions	• Gaseous combustion processes generally result in low levels of PM emissions, but not lower than the baseline GTCC power plant – Gasification-based options utilizing gas turbines and internal combustion engines must remove the PM prior to combustion to avoid damage to the power generation equipment – Rankine cycle options would require exhaust after-treatment • PM emissions for biomass co-firing with coal vary significantly with the ash content of different types of solid biomass feedstocks, but are generally lower than for coal, with averages 10% ash in the United States • Fuel cells inherently produce negligible amounts of PM emissions, as any particulates would tend to damage to the fuel cell and the fuel processor (e.g., by clogging catalyst beds)

As with conventional power, biopower PM emissions occur mainly at the power plant and not in upstream steps of the fuel chain.

Full Fuel Chain Air Emissions of Selected Biopower Options
Grid Power — PM (g/kWh delivered)

Emissions of a natural gas combined cycle plant = 0.023 g/kWh.
Emissions of a coal fired plant = 1.1 g/kWh

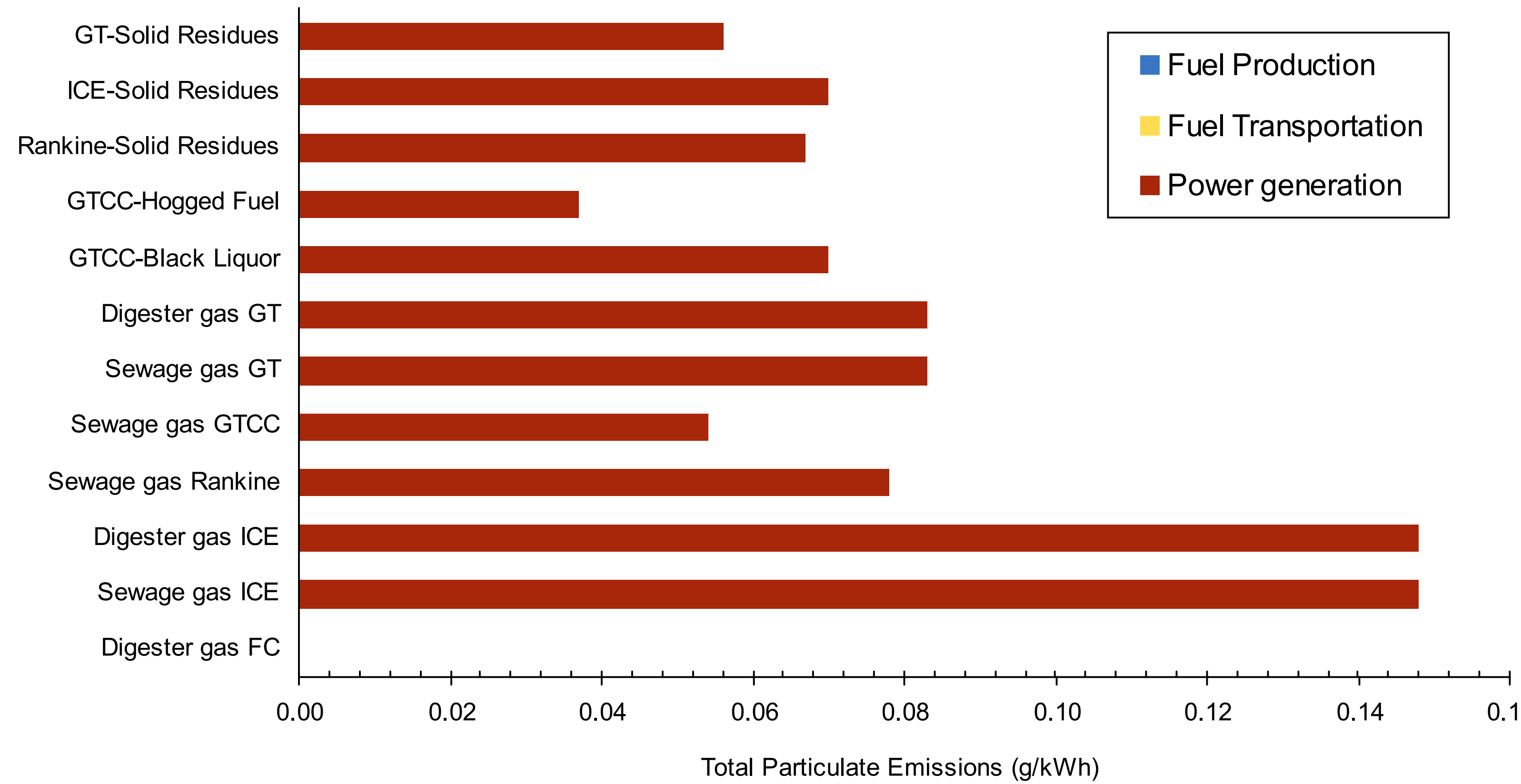


1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent.
2. The feedstocks used for the co-firing options were corn stover, wheat straw, woody biomass (poplar), and switchgrass; the range shown reflects the full chains using these other feedstocks

Biomass onsite power options are expected to produce higher PM emissions than natural gas combined cycle technology.

Full Fuel Chain Air Emissions of Selected Biopower Options
Onsite Power — PM (g/kWh produced)

Emissions of a natural gas combined cycle plant = 0.023 g/kWh



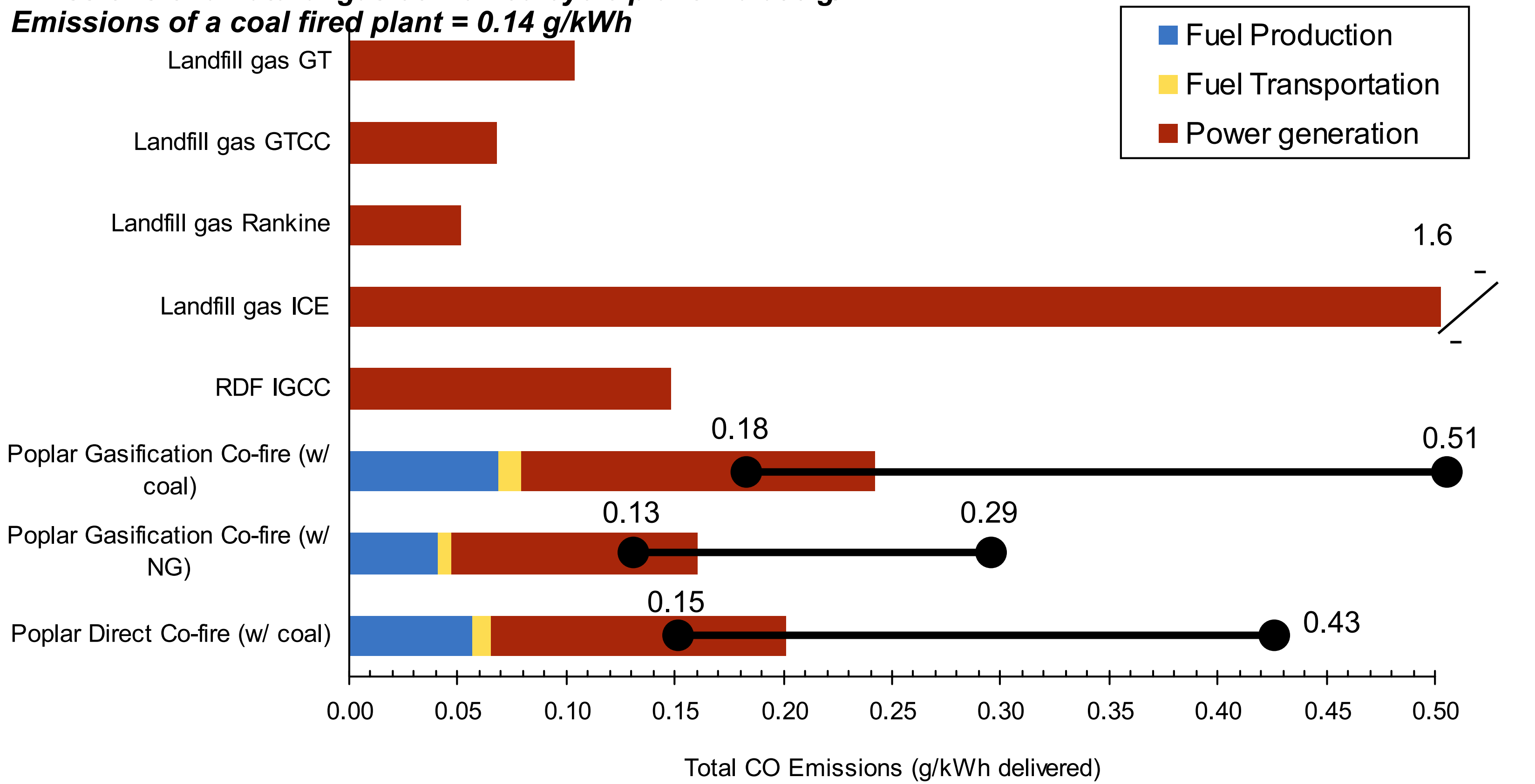
CO emissions from power generation are highly technology dependant, but upstream emissions cannot be ignored for certain feedstocks.

Assumptions and Methodology	• CO emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass • Grid-sited options include the effects of transmission & distribution energy losses (i.e., results are shown per kWh delivered) • Biogas (including landfill, sewage, and digester gas) is generated and used where it is produced so there is no energy use (and therefore no CO emissions) associated with biomass production and transport • For biomass co-firing with coal, the co-firing is assumed to have no effect on overall CO emissions • For RDF, the emissions associated with collection and processing are not included as these would need to be done regardless of the use of RDF for fuel – The non-biomass portion of RDF is also excluded
Comments	• For agricultural residues & energy crops, many biomass fuel types are possible. Poplar is used here as an example of a woody biomass resource that would be grown as an energy crop – For the remaining feedstocks (e.g., switchgrass, corn stover, wheat straw), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for poplar • CO emissions are generally uncontrolled emissions consistent with current good practices for combustion (e.g., dry low NOx combustion for gas turbines, lean burn technology for internal combustion engines) • For co-firing with coal it is assumed that biopower CO emissions are the same per BTU of fuel consumed as for the baseline coal plant, so that differences in emissions per kWh are related to differences in efficiency
Conclusions	• With the exception of the internal combustion engine, gaseous combustion processes generally result in the lowest levels of CO emissions, but not lower than the baseline GTCC power plant – Gasification-based options utilizing gas turbines and internal combustion engines have somewhat higher levels of CO emissions than biogas options, due mainly to lower overall efficiency • CO emissions for biomass co-firing with coal vary significantly with the different types of solid biomass feedstocks, as a result of different upstream (feedstock production and transport) energy requirements – Generally, emissions are roughly equal to or slightly higher than the baseline coal plant • Fuel cells inherently produce negligible amounts of CO emissions, as any residual CO in the fuel gas is burned in a low-emissions burner to generated heat to run the fuel processor

As with PM, the bulk of CO emissions occur in the power generation step.

Full Fuel Chain Air Emissions of Selected Biopower Options
Grid Power — CO (g/kWh delivered)

Emissions of a natural gas combined cycle plant = 0.086 g/kWh.
Emissions of a coal fired plant = 0.14 g/kWh

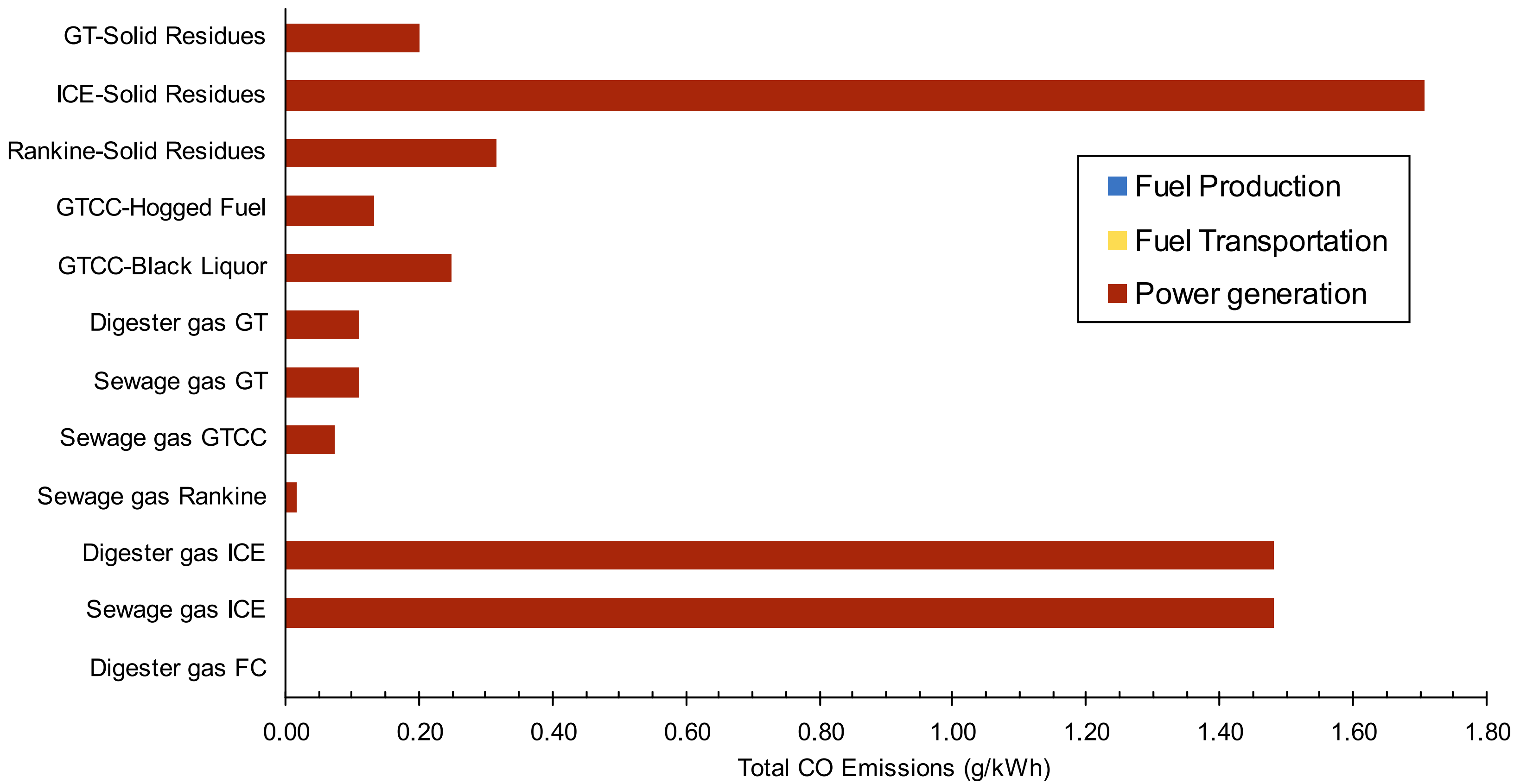


1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent.
2. The feedstocks used for the co-firing options were corn stover, wheat straw, woody biomass (poplar), and switchgrass; the range shown reflects the full chains using these other feedstocks

Onsite power does not seem to provide appreciable CO reduction benefits compared to natural gas combined cycle technology.

Full Fuel Chain Air Emissions of Selected Biopower Options
Onsite Power — CO (g/kWh produced)

Emissions of a natural gas combined cycle plant = 0.086 g/kWh.



In addition to air emissions, biomass power can produce solid wastes and water effluent, but impacts are expected to be modest and manageable.

Solid Waste

- Ash production is the most significant solid waste issue, since typical biomass fuels contain 1-2 percent ash by weight, and some contain as much as 15 percent
  - Biomass ash is generally non-toxic and is capable of being used, and even sold, for beneficial purposes (e.g., fertilizer)
  - Recovery and disposal costs and permitting are considerations when evaluating project economics, but they have not been included explicitly in the COE calculations
- For biomass co-firing with coal, using biomass would reduce current rates of ash generation
- For MSW or RDF, solid waste management will be of particular concern, but new plants should be able to meet high standards for solid waste management

Effluent Waste

- Effluent can originate from a number of sources, but is usually preventable
  - Effluent from wet scrubbers is typically filtered and recycled, and the solids are de-watered for handling as solid wastes
  - Most new plants utilize electrostatic precipitators instead of wet scrubbers, eliminating effluent altogether
  - Facilities may have to monitor or control storm and wash-down runoff, which may contain substances leached from biomass storage and handling areas
  - Effluent can contain suspended solids and BOD[1], but toxicity is not usually a serious concern
- A more serious water-related issue is the expected demand and runoff associated with large-scale energy crop production

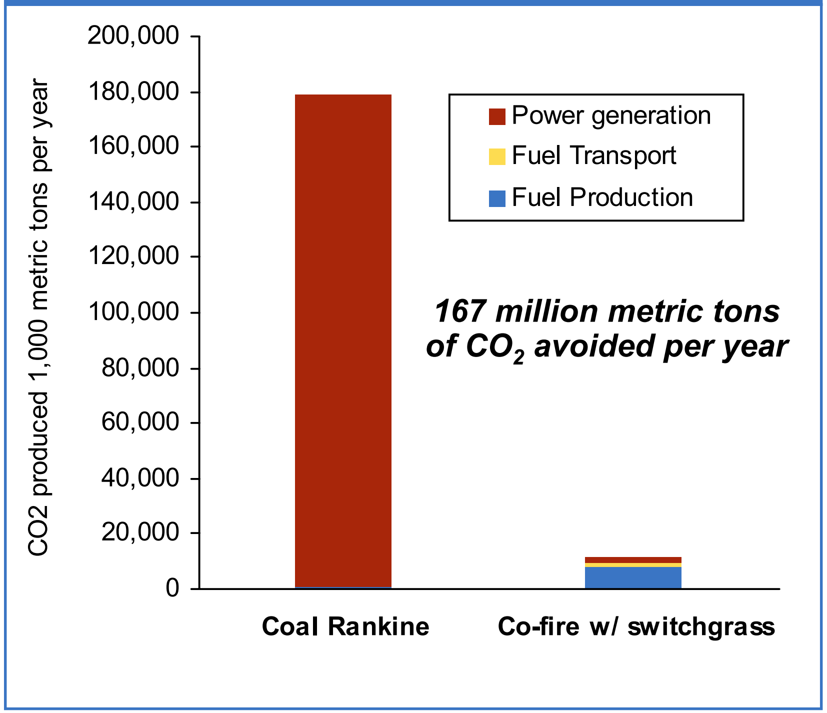
[1] Biological Oxygen Demand, which is a measure of the potential of organic wastes to compete with aquatic life for dissolved oxygen

Direct biomass co-firing with coal is used as an illustration of the possible environmental benefit of biomass power, if deployed aggressively.

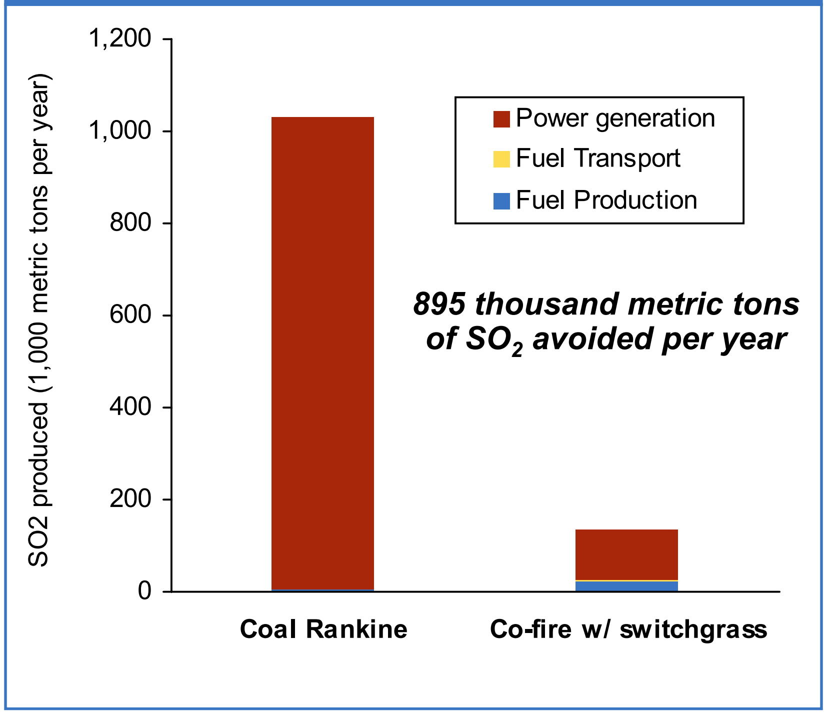
- Biomass co-firing with coal alone could result in a 6-fold increase in biopower generation over the baseline of 56,000 GWh/year
- Switchgrass was taken as an example as its potential use alone could almost reach the aggressive goal (158 thousand GWh)
- The total amount of available switchgrass was used to generate power by directly co-firing with coal
- The resulting emissions were ratioed to an equivalent of 170 thousand GWh (the biopower aggressive goal) as a thought experiment
- The resulting possible total benefit of co-firing provides an illustration of potential environmental benefits of biopower
- The biomass capacity was compared with the equivalent coal Rankine capacity to estimate emissions reductions

At high levels of market penetration, biomass co-firing produces significant CO_2 and SO_2 reductions. Moreover, the total investment cost for CO_2 reductions is estimated to be a modest $30/ton.

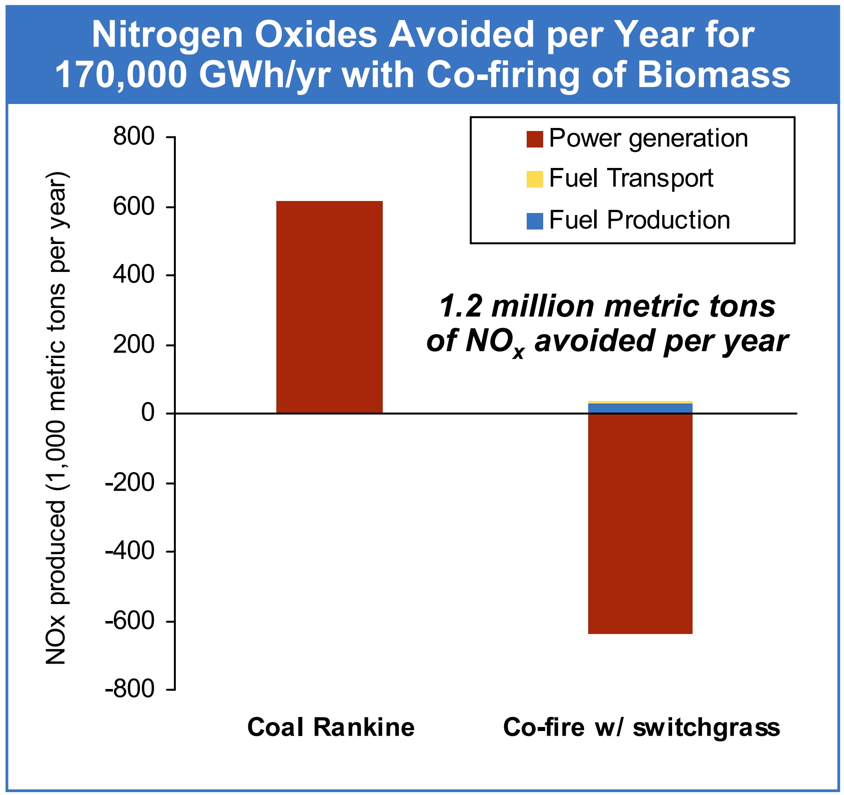
Carbon Dioxide Avoided per Year for 170,000 GWh/yr with Co-firing of Biomass



Sulfur Dioxide Avoided per Year for 170,000 GWh/yr with Co-firing of Biomass

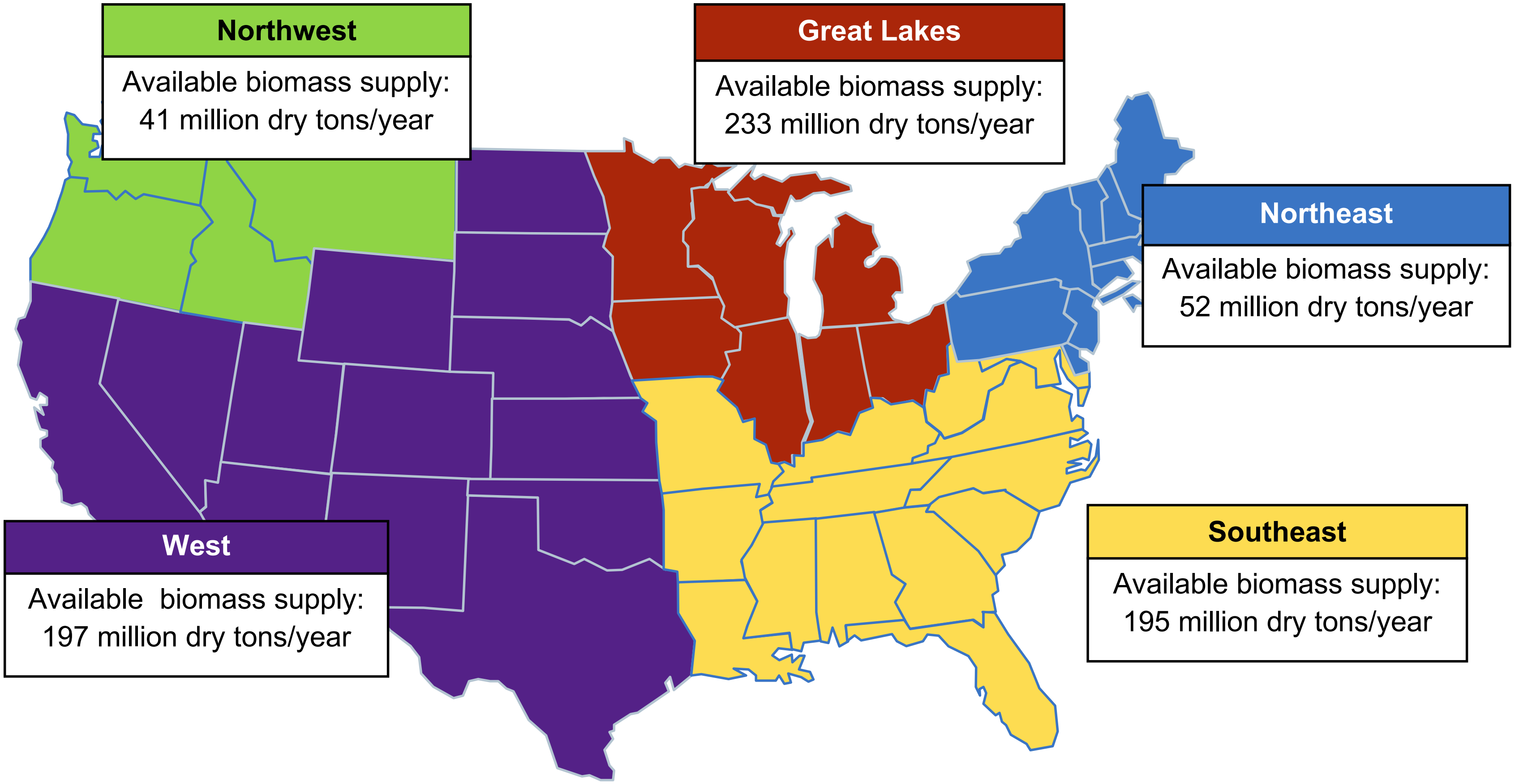


Co-firing has the potential to achieve significant NOx reductions because emissions are reduced for the entire coal plant, not just the biomass fraction.



At the high level of market penetration shown here (roughly 10% of current coal-fired power generation), approximately 20% of total power sector NOx emissions are eliminated.

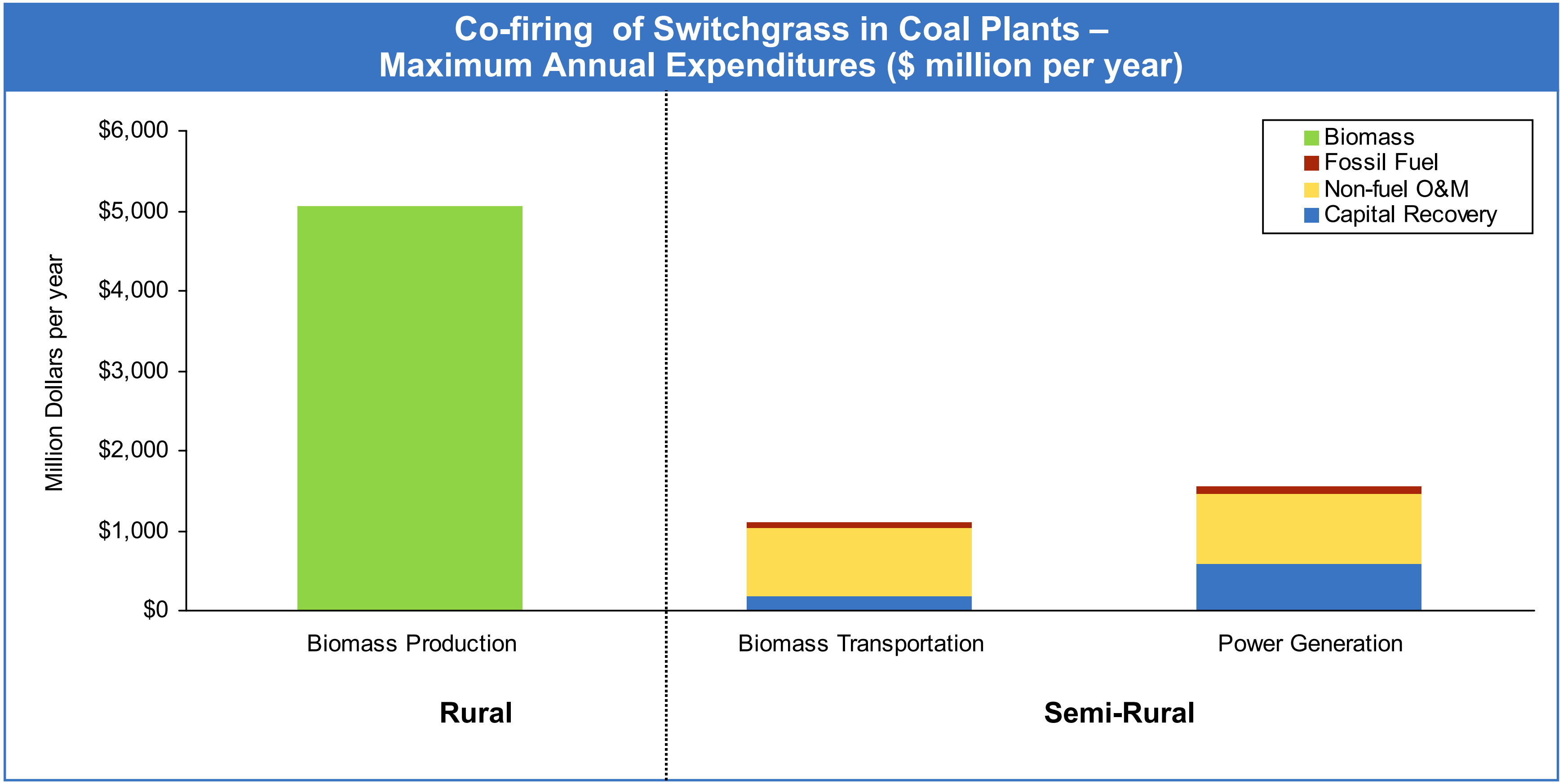
The definition of regions is based by the Regional Biomass Energy Program.



The method of analysis has implications in the conclusions for possible economic impact of accelerated biomass use for power.

- We assumed that the capital investment associated with biomass production is contained in the feedstock price
- One weakness of this method is that it does not account for any additional investment of equipment that is needed to collect the biomass not currently harvested
- The same thought experiment used to illustrate environmental benefits is used here to illustrate the possible impacts of accelerated biomass use using biomass co-firing with coal
- The investments shown produce a total of 170,000 GWh of electricity per year using switchgrass for direct co-firing in coal plants

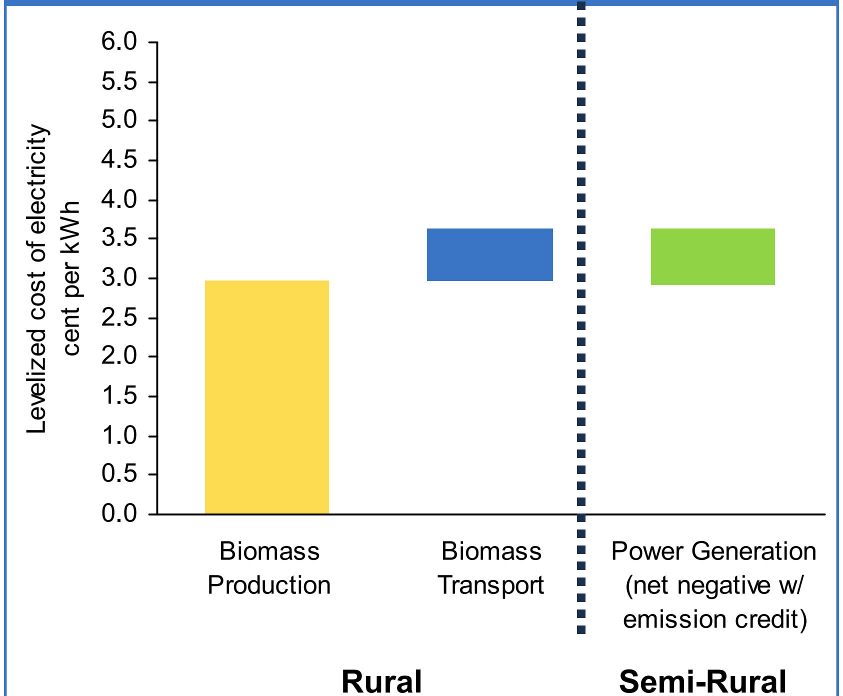
For biomass co-firing, the single largest annual operating cost item is expected to be the biomass fuel itself.



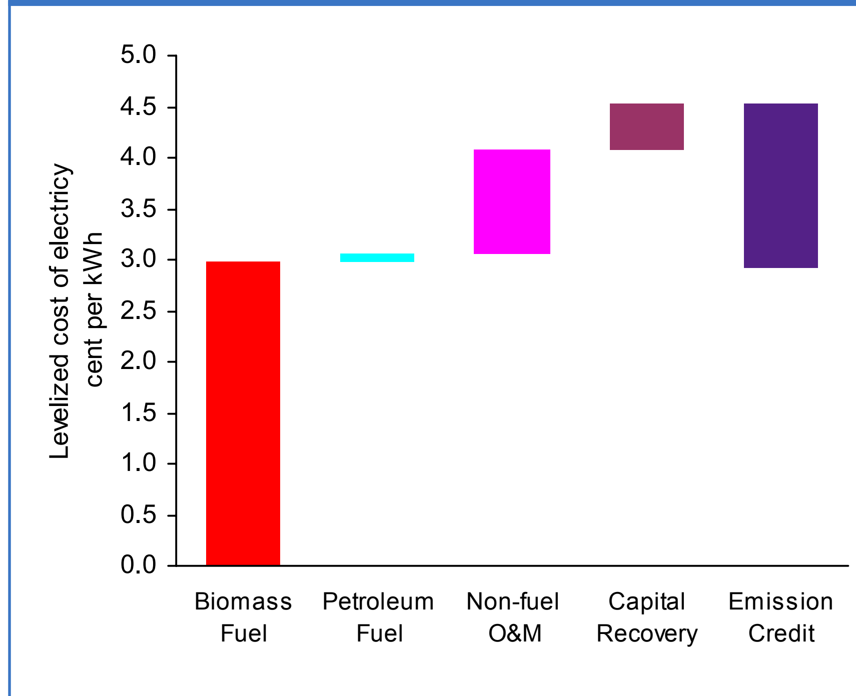
1. Capital recovery assumptions are 13% per year for biomass transport investments and 15% for power plant investments.
2. The feedstock cost of switchgrass is assumed to be $40 per ton (dry basis). The capital and operating costs of biomass production are incorporated into this price.
3. The investments shown produce a total of 170,000 GWh of electricity per year switchgrass co-firing with coal.

Value creation for electricity generation is primarily in the biomass fuel; emission credits could cover the cost of nonfuel O&M and capital recovery.

Switchgrass Direct Co-Firing With Coal Levelized Cost of Electricity, cent per kWh



Switchgrass Direct Co-Firing With Coal Levelized Cost of Electricity, cent per kWh



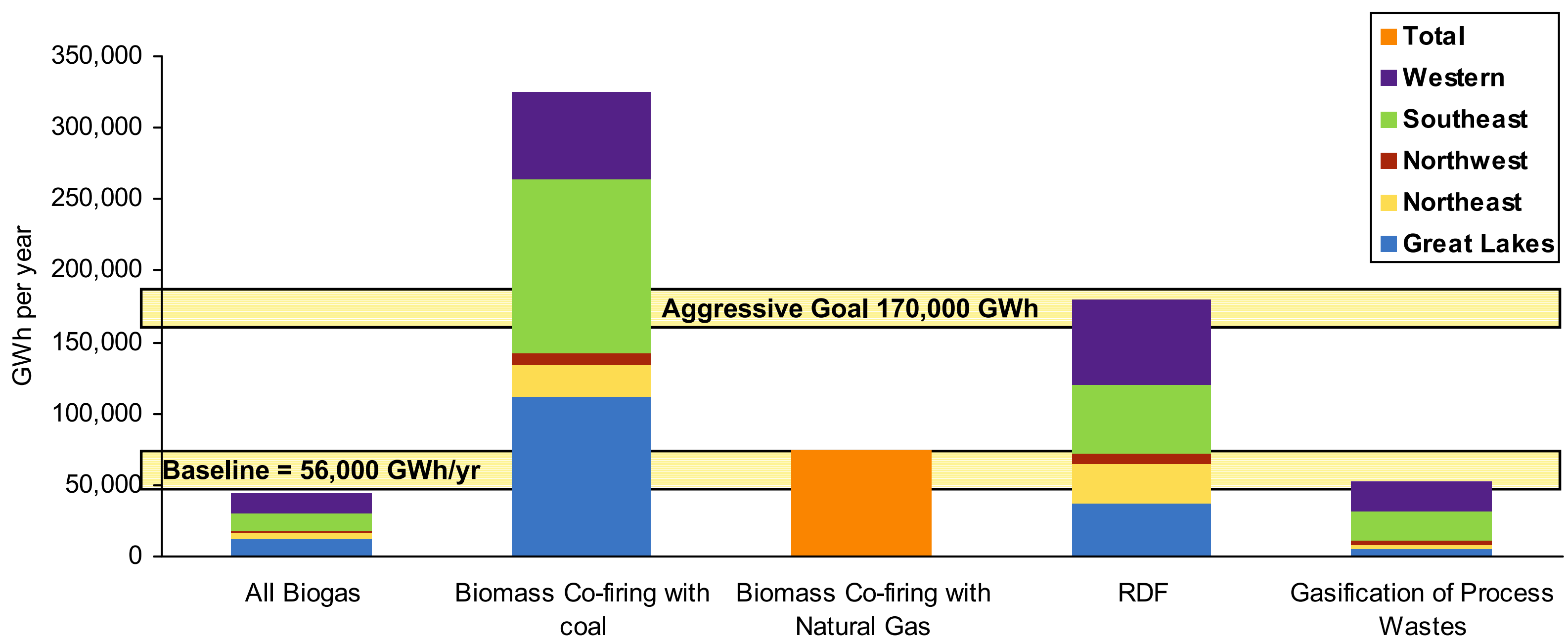
1. Capital recovery cost per year are a 13% per year for biomass transport investment and 15% for power generation investment. The capital recovery for biomass production is included in the price for biomass.
2. The fuel operating cost for biomass production is solely the cost of the biomass. The capital, non-fuel operating, and petroleum fuel costs in biomass production are incorporated into the price for biomass
3. The feedstock cost of switchgrass is $40 per dry ton

Several biomass power options appear attractive and would generally not compete directly with one another for biomass resources.

- The most attractive near-term option overall appears to be biomass co-firing with coal
  - At the macro level there do not appear to be any significant market limitations, but implementation will require finding suitable power plants in close proximity to the biomass resource, which will be mainly conventional options such as wood, wood waste, crop residues and eventually, energy crops
- Utilization of various biogases appears similarly attractive as biomass co-firing with coal, although the total market potential is considerably smaller
  - Power generation is the most logical use for this resource
- The price premiums associated with the gasification of biomass co-firing with natural gas-fired GTCC plants are somewhat higher than those for biomass co-firing with coal
  - At the macro level, the limitation appears to be GTCC capacity, not overall resource availability
- The gasification of refuse derived fuel (RDF) could be an attractive option for meeting the goal of aggressive growth of biopower production
  - The main issues are the somewhat higher price premiums and overcoming the considerable public resistance to increased use of municipal waste for energy, despite the growing problem with landfill space
- Although the market appears limited, the gasification of process wastes (including the P&P industry) can be cost competitive and should therefore be exploited whenever it is technically and economically feasible

Biomass co-firing with coal represents by far the largest opportunity – if the technical potential were fully exploited, co-firing alone would represent a 6-fold increase in biomass power generation.

Maximum Biopower Market (technical potential)



1. The bars represent using the entire resource to generate electricity with the most efficient technology.
2. Biogas market includes use of landfill gas, digester, and sewage gas. The bar represents using the entire resource to generate electricity with an efficiency of 32 percent which includes energy losses from transmission and distribution of 7.2 percent.
3. Biomass co-firing with coal market is limited by coal capacity not resource capacity per region. The shown market is 15 percent of available coal plant capacity in each region.
4. The total market for biomass co-firing with natural gas market is capacity limited. The market shown is based on EIA estimates of new GTCC installations in the 2000-2010 timeframe. The market shown is 15 percent of available new natural gas combined cycle capacity.
5. RDF includes the use of gasified RDF in the most efficient technology available.
6. Gasification of process wastes include black liquor, hogged fuel, and solid residues with the most efficient technology available.

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All fuel options are compared against a petroleum based fuel chain and a MTBE/reformulated gasoline fuel chain excluding state and federal taxes.

	Baseline for Emissions	Value in Use	Comments
Pure or Neat Ethanol	Petroleum Gasoline Fuel Chain	• $0.91 per gallon gasoline equivalent • $21.4 per barrel crude oil price	• Ethanol chains are compared to petroleum gasoline chain using a spark ignition engine car • A premium value of the ethanol (from increased octane or oxygenate content) was not taken
Blended Ethanol	Reformulated Gasoline Fuel Chain	Based on its octane barrel value, see note below EtOH: $1.01/gal MTBE: $0.99 to 1.09/gal	• The baseline uses reformulated gasoline with 11% by volume MTBE • For blended ethanol fuels, only the biomass portion of the fuel is shown in both the economics and environmental impact calculations • The cost and environmental impact of gasoline is not included • Spark ignition engines are used
FT-Diesel	Petroleum Diesel Fuel Chain	• $0.83 per gallon gasoline equivalent • $21.4 per barrel crude oil price	• FT-Diesel chains are compared to petroleum diesel chain using a compression ignition engine vehicle • A premium value of the biomass fuel was not taken

Octane Barrel Valuation	• The value of blended ethanol was set according to its octane barrel value compared to gasoline • 1998-2000 petroleum marketing monthly data was used to assess a value of $0.28 per octane point per barrel of gasoline • The 2010 wholesale price of motor gasoline was $0.85 per gallon from EIA 2001 Energy Outlook • ADL assumed an average octane of 89 for the wholesale gasoline • Ethanol octane was a (R+M)/2 value of 113; MTBE (R+M)/2 value of 109.5 • No further premiums were assigned for ethanol • MTBE average premium during the time period was 11 percent over its octane value • The price for MTBE is $41.4 to $46.0 per barrel ($0.99 to 1.09 per gal MTBE); EtOH octane price is $42.4/B or $1.01/gal

The whole fuel chain was considered for the emission calculations. Vehicle efficiency has been taken into account.

- Regulated emissions for each fuel are set by the relevant emission standards
- Carbon dioxide and sulfur dioxide are based upon the elemental composition of the fuel and the chain efficiency
- NOx, CO, and nonmethane hydrocarbon standards are set by the 50,000 mile durability ULEV standards for 2001-2006 Model Year for All passenger car’s and light-duty trucks (0-3750 lbs LVW)
- Particulate matter for compression ignition engines are the 100,000 mile durability standards for new 2001-2003 Model Year TLEV passenger cars and light duty trucks
- Methane emissions are calculated from correlations based on the amount on nonmethane hydrocarbon emissions
- The effect of ethanol as an oxygenate on emissions in the vehicle was not taken into account

The vehicle emissions are based on that the vehicle is designed to meet the emission standard (ULEV), regardless of the fuel used.

The efficiency of pure ethanol fueled cars is enhanced over gasoline fueled engines. All other fuels have the same efficiency as its respective baseline.

Vehicle Efficiencies

	Efficiency
Gasoline	15.7%
Diesel	16.9%
RFG	15.7%
Pure Ethanol	17.3%
FT Diesel	16.9%
DME	16.9%
Blended Ethanol	15.7%

Fuel Properties for Reference

	HHV of fuel, GJ per million gallons	Equivalent in terms of gallons of gasoline equivalent
Gasoline	129,072	1.0
Ethanol	88,590	0.686
Dimethyl ether	80,400	0.623
FT Diesel	138,381	1.07

Biofuels can offer tremendous carbon dioxide reduction savings compared to petroleum fuels even when used as primarily a blending agent.

- Biofuels offer the only remotely affordable option to drastically reduce CO2 emissions from transportation fuel chains
- When used as an oxygenate in RFG, ethanol could play a critical role in criteria pollutant emissions reduction
- Without legislative protection of the clean fuel benefit of biofuels when used as a neat fuel, these benefits may be lost in re-optimization of engines for power or cost
- In all cases CO2 reductions (per mile driven) are significant, ranging from 65-95 percent
  - The only net CO2 emissions are associated with biomass production and transport, and use of machinery at the processing plants for biomass handling
  - Further improvements in biomass handling methods within the plant processing gate will reduce chain carbon dioxide emissions
- Even though biomass fuels are low in sulfur, net chain emissions are comparable with petroleum chains
  - The emissions associated with biomass production are for fertilizer use and petroleum fuels for harvesting
  - Transporting the biomass contributes negligible emissions (assuming 50-mile one-way trips on average)
  - Production of fuel, especially for ethanol, is associated with internal power generation which does not have sulfur control
    - Lignin and waste streams are used for power generation with associated sulfur from water treatment, acidification, and biomass sulfur itself
    - Additional technology such as dual alkali technology could be employed with additional capital expense
  - Gasification based processes have lower sulfur emissions due to removal in processing steps and use of resulting low-sulfur diesel and syngas as fuels internally
- The solid and water effluent waste is expected to be manageable
  - Solid wastes are expected to be biodegradable and usable as fuel (e.g. Cell mass)
  - Water will contain suspended solids and toxicity is not a serious concern
  - Water use for processing (especially for fermentation) may be a concern in arid or semi-arid regions

Emissions of NOx, methane, nonmethane hydrocarbons, particulate matter, and CO are comparable to that of petroleum derived fuels.

- Depending on the conversion technology and feedstock, NOx, CH_4, NMHC, particulate matter and CO emissions can be comparable or higher
- Vehicle related emissions will likely be governed by emission standards and be mostly independent of fuel used
- The predominate step which contributes emissions is the actual processing step to make the fuel
  - Emissions are related to the use of petroleum fuels to handle the biomass within the plant gate
  - Additional emissions are generated from combustion of waste gases and waste solids for onsite power generation
- Increased use of state-of-the-art technology for biomass handling and internal power generation will improve chain emissions further

The emissions in the vehicle end-use were assumed to meet the emission standard regardless of the fuel used.

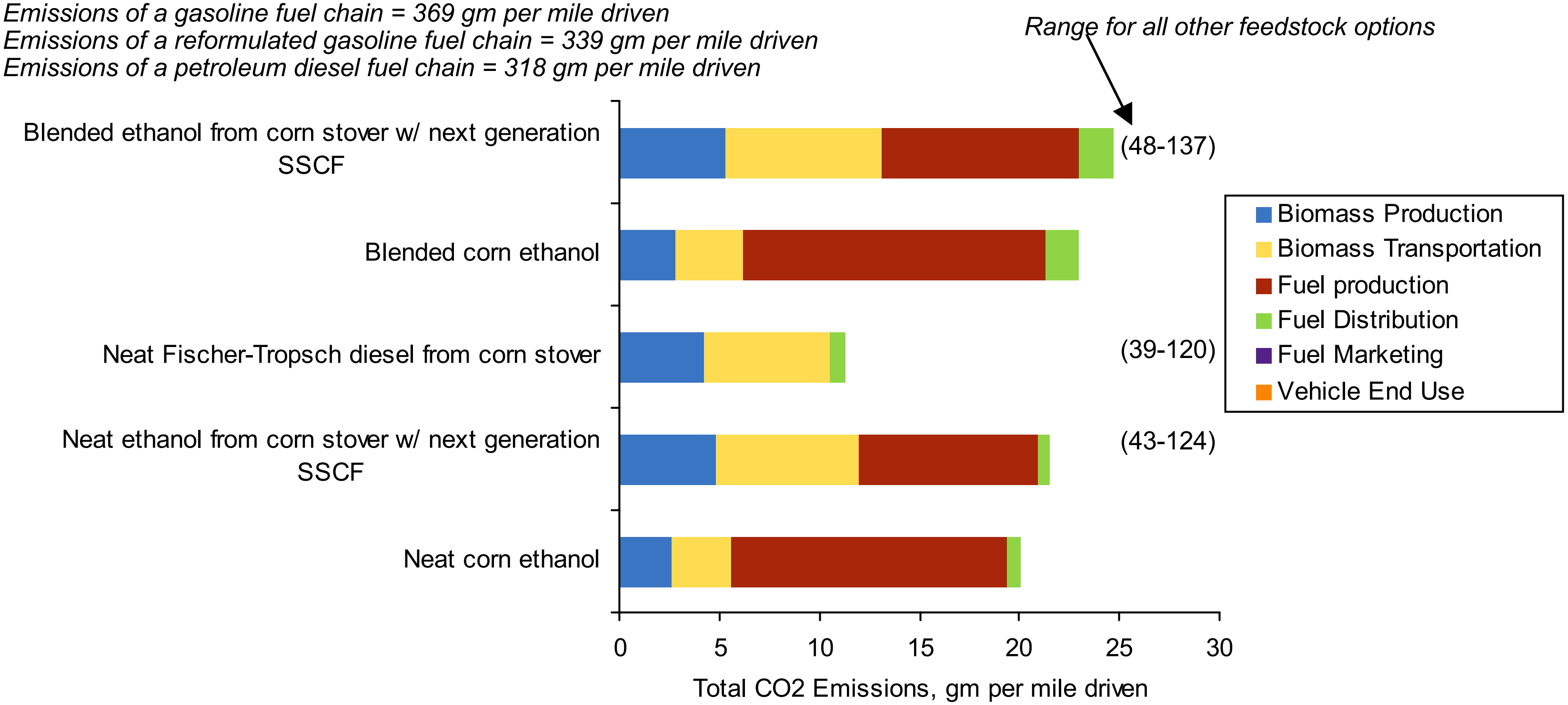
All biofuels options produce significant (~65-95%) reductions in CO_2 emissions, per mile driven.

Assumptions and Methodology	• CO_2 emissions from the utilization of the biomass fuel itself in the engine are assumed to be zero (closed-loop carbon cycle) – CO_2 emissions occur when other fuels and materials (e.g., chemical fertilizers, petroleum fuels) are used to grow, harvest, transport and process the biomass
Comments	• For agricultural residues & energy crops, many biomass fuel types are possible. Corn stover is used here as an example. For the remaining solid biomass feedstocks (e.g., woody biomass, wheat straw, switchgrass), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for corn stover • The CO_2 emissions shown are generated primarily from fossil fuels required (mostly diesel fuel) for harvesting the biomass, and transporting the biomass to the processing plant and internal plant requirements. The processing plant requirements are mainly for moving the biomass around the plant within the plant gate. All options used comparable diesel fuel on a biomass weight input basis
Conclusions	• Biofuel CO_2 emissions are comparable between biomass production (harvesting) and processing of the biomass to produce the fuel • Methods to reduce biomass handling/transport within the plant site will impact the carbon dioxide emissions for the entire chain • Harvesting methods used will dramatically impact biomass fuel chain emissions which are directly attributed to fossil fuels used in harvesting and any fertilizer use • Biomass fuels offer significant benefits in carbon dioxide reduction compared to the fuel chain emissions of petroleum derived fuels

Carbon dioxide emissions are associated primarily with the production of the fuel.

Air Emissions of Sample Fuel Options
CO_2 emissions, grams per mile driven

Emissions of a gasoline fuel chain = 369 gm per mile driven
Emissions of a reformulated gasoline fuel chain = 339 gm per mile driven
Emissions of a petroleum diesel fuel chain = 318 gm per mile driven

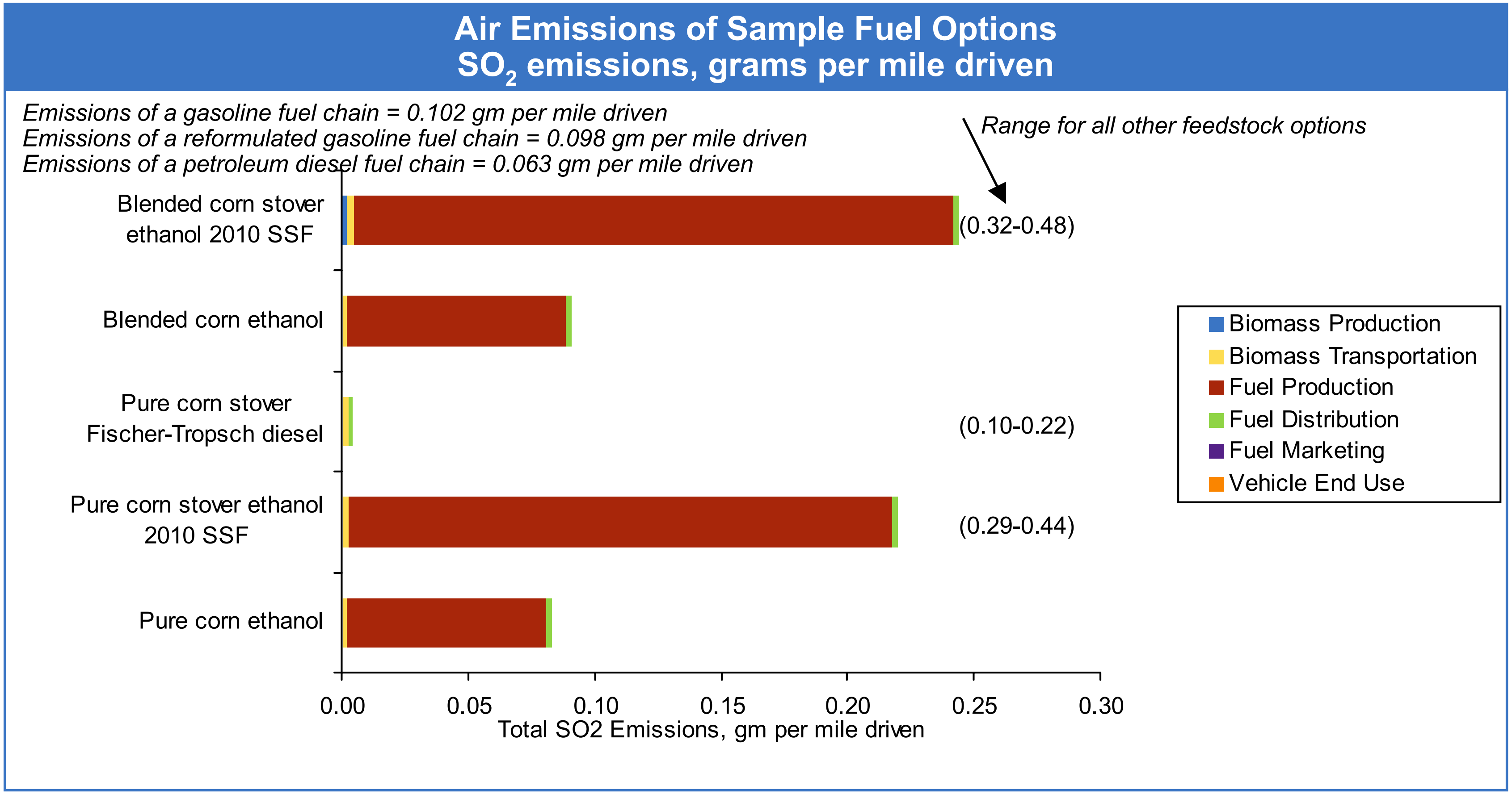


The end use CO_2 emissions are zero for biomass fuels by a closed carbon balance.

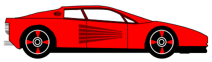
Biofuels do not offer significant benefits for sulfur dioxide reduction compared to petroleum-derived fuels when the whole chain is viewed.

Assumptions and Methodology	• SO_2 emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass • The SO_2 vehicle emissions are assumed to be equivalent to the sulfur content of the fuel; no sulfur capture controls occur in the vehicle • Sulfur dioxide emissions for FT-diesel chains are lower than that for ethanol primarily because sulfur-free FT-diesel is used within the plant processing gate to move the biomass within the processing plant
Comments	• For agricultural residues & energy crops, many biomass fuel types are possible. Corn stover is used here as an example. For the remaining solid biomass feedstocks (e.g., woody biomass, wheat straw, switchgrass), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for corn stover • The SO_2 emissions shown are generated primarily from fossil fuels required (mostly diesel fuel) for harvesting the biomass, and transporting the biomass to the processing plant and internal plant requirements. • Sulfur emissions for ethanol chains for the processing step are associated with power generation, predominately. The process takes mainly lignin and process waste streams for fuel in combustors to generate steam for power generation. In the case of cellulosic ethanol, the analysis assumed that lignin, water treatment solids (containing H2S), solids from neutralization tanks (containing sulfuric acid), and sulfur in the biomass itself is all converted to SO2 in the combustor. It is assumed that 1% of the SO2 emissions are converted into sulfuric acid. Presumably the SO2 emissions in the processing step can be reduced with technology such as a dual alkali process technology with the associated incremental cost which is not shown here.
Conclusions	• Biomass transport and handling add little SO_2 emissions • The sulfur dioxide emissions shown are directly attributable to internal power generation using lignin and waste streams for cellulosic ethanol. A smaller portion (<10% of the emissions) is associated with petroleum diesel use within the processing plant gate to move and handle the biomass within the plant site. • Sulfur capture technology such as dual alkali scrubbing technology can drastically cut the sulfur emissions associated in the processing step with additional cost • Biomass fuels themselves are low in sulfur so that vehicle related SO_2 emissions are low • FT diesel chains used FT diesel as the fuel (which is sulfur free). Syngas was also used in power generation which is also sulfur free, resulting in low sulfur emissions during the processing step

Most of the sulfur emissions are associated with diesel engines used to handle the biomass on-site.



FT-diesel is essentially sulfur free since any sulfur present in the biomass is removed prior to the fuel synthesis.



Biomass fuels do not provide appreciable benefits in nitrogen oxides reduction compared petroleum derived fuels.

Assumptions and Methodology

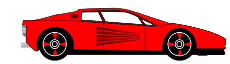
- NOx emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass
- The vehicle emissions of NOx are set to the 50,000 mile durability ULEV standards for 2001-2006 model year for all passenger cars and light-duty trucks (0-3750 lbs LVW)
- It is assumed that the engine will be designed to meet the emission standard regardless of the fuel used; therefore all chains have the same emissions per mile driven for the end use step
- The emission factors used for diesel engines used in biomass production, biomass transportation, and engines used at the processing plant use 50/50 emissions which represent that an average of 1/2 of the engines used are state-of-the-art and 1/2 are uncontrolled

Comments

- For agricultural residues & energy crops, many biomass fuel types are possible. Corn stover is used here as an example. For the remaining solid biomass feedstocks (e.g., woody biomass, wheat straw, switchgrass), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for corn stover
- The NOx emissions shown are generated primarily from fossil fuels required (mostly diesel fuel) for harvesting the biomass, and transporting the biomass to the processing plant and internal plant requirements. The processing plant requirements are mainly for moving the biomass around the plant within the plant gate. All options used comparable diesel fuel on a biomass weight basis

Conclusions

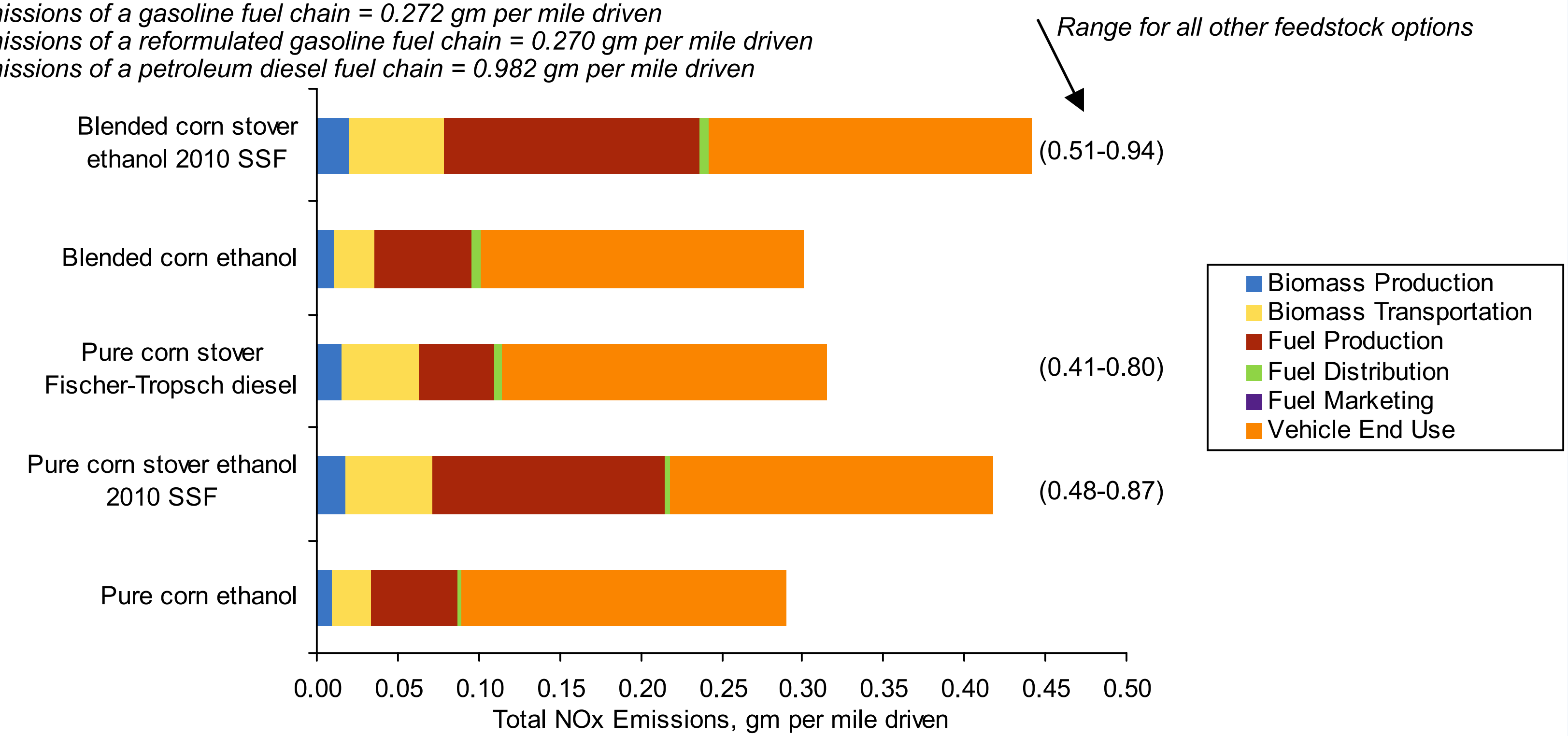
- Biomass-only options do not result in lower NOx emissions relative to the petroleum-derived fuels
- NOx emissions are generated primarily in combustion applications. For the vehicle end use, it is assumed that the vehicle emissions are the same for all biofuels used
- The main avenue to reduce biomass fuel chain emissions is the use of state-of-the-art engines and combustion turbines with reduced NOx generation capability for biomass harvesting, transportation
- The main generator of NOx emissions is within the fuel processing gate which can be reduced with the use of more state-of-the-art equipment

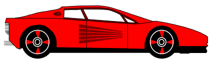


Most nitrogen oxides are generated on the vehicle. Engine manufacturers typically tune the engines to just meet emissions specifications.

Air Emissions of Sample Fuel Options
NO_x emissions, grams per mile driven

Emissions of a gasoline fuel chain = 0.272 gm per mile driven
Emissions of a reformulated gasoline fuel chain = 0.270 gm per mile driven
Emissions of a petroleum diesel fuel chain = 0.982 gm per mile driven

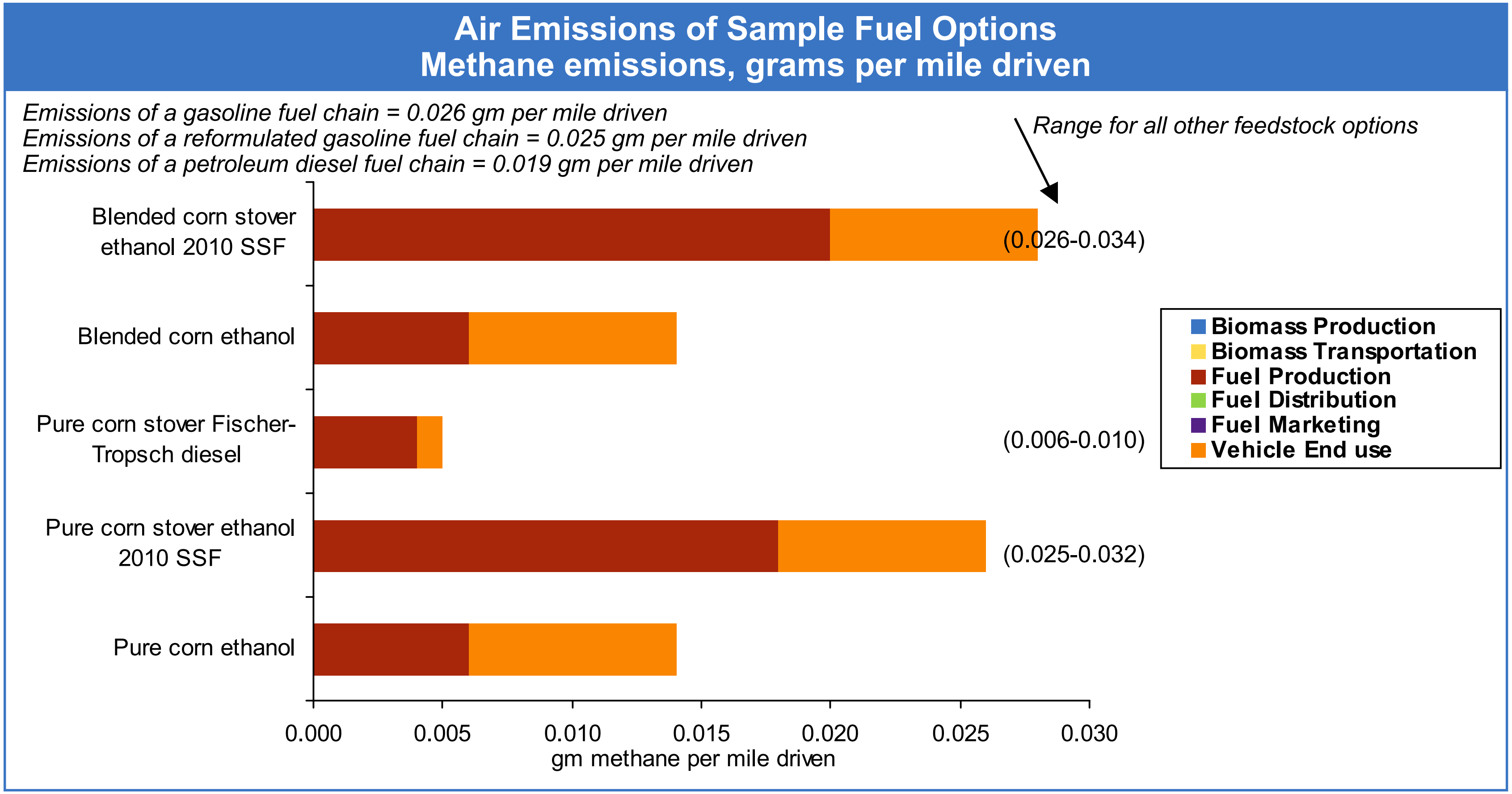




Data for methane emissions from the vehicle is not widely available. Most methane is generated within the plant processing gate.

Assumptions and Methodology	• Methane emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass • Methane emissions for the vehicle are calculated from correlations based on the amount on nonmethane hydrocarbon emissions
Comments	• For agricultural residues & energy crops, many biomass fuel types are possible. Corn stover is used here as an example. For the remaining solid biomass feedstocks (e.g., woody biomass, wheat straw, switchgrass), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for corn stover • The methane emissions shown are generated primarily from fossil fuels required (mostly diesel fuel) for internal plant requirements. The processing plant requirements are mainly for moving the biomass around the plant within the plant gate
Conclusions	• Methane emissions associated with biomass production/harvesting and biomass transportation to the processing plant are minimal • Vehicle emissions are dictated by the standards for nonmethane hydrocarbons • Improved processing plant controls will favorably impact biomass fuel chain emissions • Biomass fuel chain methane emissions are comparable to petroleum chain emissions for methane

Methane emissions are associated with processing (process gas combustion) and diesel engine emissions.



The situation with NMHCs is similar to that for methane – biomass yields comparable NMHC emissions as for petroleum-derived fuels.

Assumptions and Methodology

- NMHC emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass, and evaporative emissions at the fuel pump
- The vehicle emissions of NMHC are set to the 50,000 mile durability ULEV standards for 2001-2006 model year for all passenger cars and light-duty trucks (0-3750 lbs LVW)
- It is assumed that the engine will be designed to meet the emission standard regardless of the fuel used; therefore all chains have the same emissions per mile driven for the end use step
- The emission factors used for diesel engines used in biomass production, biomass transportation, and engines used at the processing plant use 50/50 emissions which represent that an average of 1/2 of the engines used are state-of-the-art and 1/2 are uncontrolled.

Comments

- For agricultural residues & energy crops, many biomass fuel types are possible. Corn stover is used here as an example. For the remaining solid biomass feedstocks (e.g., woody biomass, wheat straw, switchgrass), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for corn stover
- The NMHC emissions shown are generated primarily from fossil fuels required (mostly diesel fuel) for internal plant requirements and evaporative emissions for fuel marketing

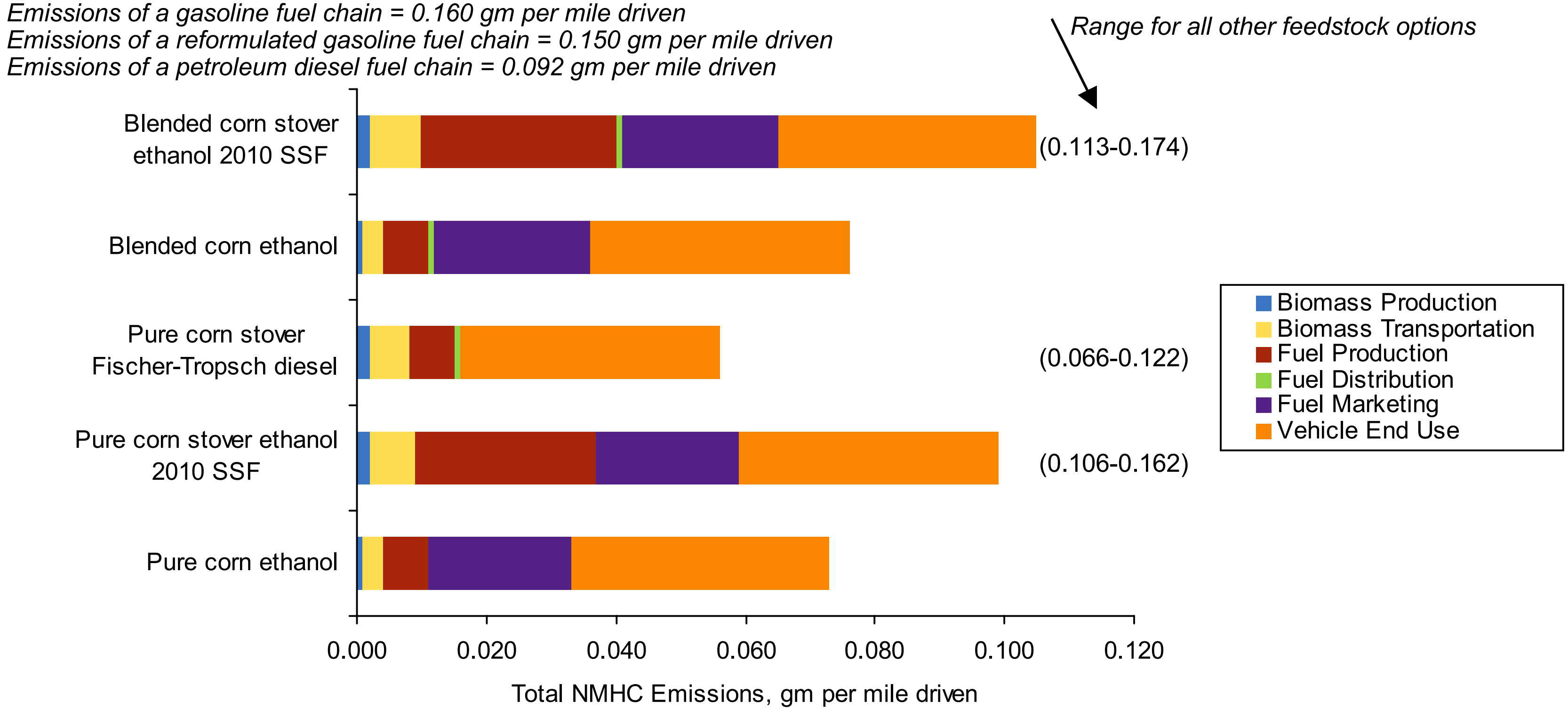
Conclusions

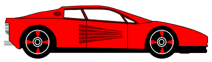
- Biomass fuels may not offer any benefits for the vehicle since the engine will likely be designed to meet the emission standards regardless of the fuel used
- Evaporative emissions for especially ethanol is an issue since the Reid vapor pressure of ethanol is higher than for current gasoline mixes used. This has implications on the use of ethanol for blending which will require additional petroleum capacity to lower the overall vapor pressure of the ethanol/gasoline mixtures
- Pure use of ethanol might require additional investments in vehicle equipment and fueling equipment to account for the high vapor pressure of ethanol so that evaporative emissions are kept under control

Most non-methane hydrocarbon emissions are associated with evaporative losses and emissions associated with actual vehicle use.

Air Emissions of Sample Fuel Options
Non-methane hydrocarbon emissions, grams per mile driven

Emissions of a gasoline fuel chain = 0.160 gm per mile driven
Emissions of a reformulated gasoline fuel chain = 0.150 gm per mile driven
Emissions of a petroleum diesel fuel chain = 0.092 gm per mile driven





Biomass fuels will offer comparable chain particulate matter emissions compared to petroleum-derived fuels.

Assumptions and Methodology

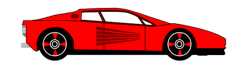
- Particulate matter emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass
- The vehicle emissions of particulate matter for gasoline spark ignition engines are assumed to be negligible. Those for compression ignition engines are set to the 100,000 mile durability standards for new 2001-2003 Model Year TLEV passenger cars and light duty trucks
- The benefits of FT-diesel in reduced PM emissions are not taken into account; it was assumed the vehicle would be designed to meet the relevant standard. Therefore, all diesel replacement chains have the same emissions per mile driven for the end use step regardless of fuel used
- The emission factors used for diesel engines used in biomass production, biomass transportation, and engines used at the processing plant use 50/50 emissions which represent that an average of 1/2 of the engines used are state-of-the-art and 1/2 are uncontrolled

Comments

- For agricultural residues & energy crops, many biomass fuel types are possible. Corn stover is used here as an example. For the remaining solid biomass feedstocks (e.g., woody biomass, wheat straw, switchgrass), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for corn stover
- The PM emissions shown are generated primarily from fossil fuels required (mostly diesel fuel) for internal plant requirements

Conclusions

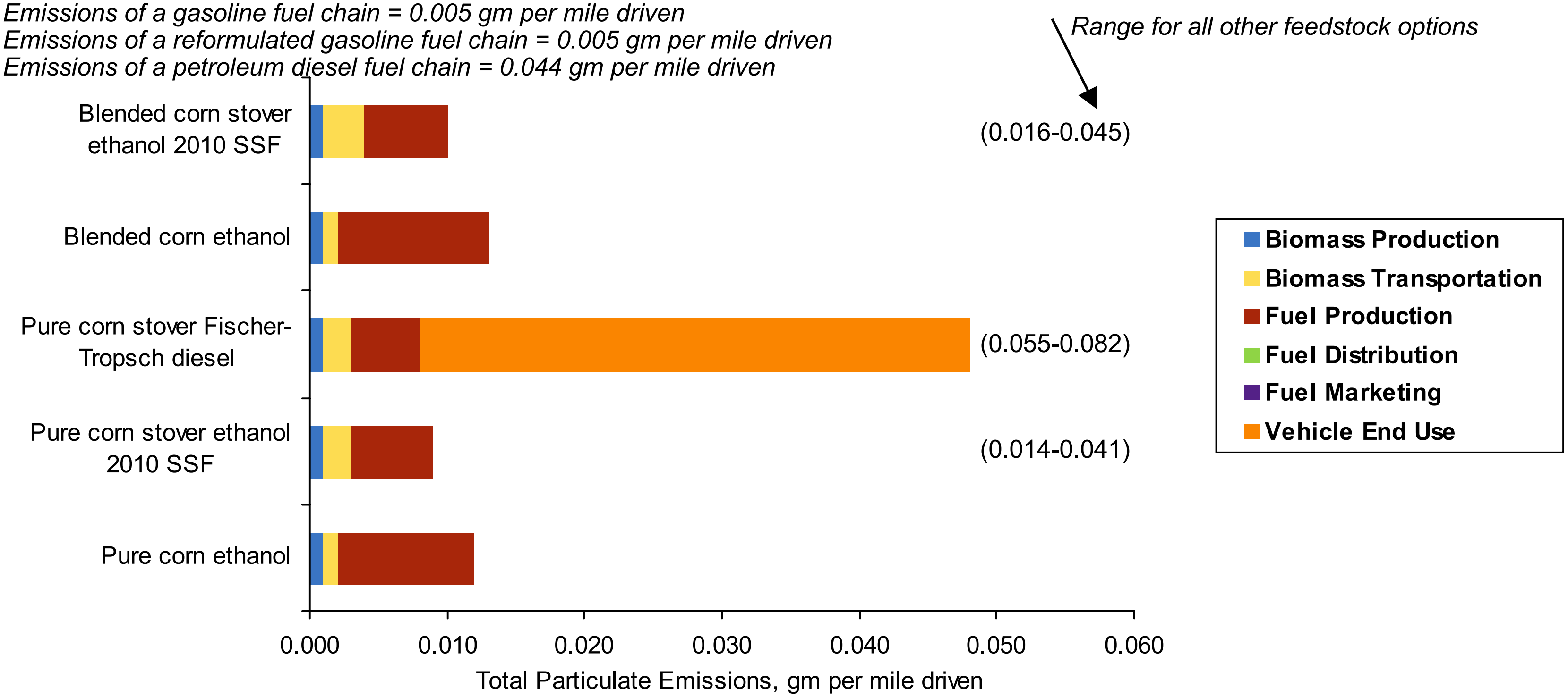
- Biomass derived fuels will offer comparable particulate matter emissions compared to petroleum-derived fuels; It is likely the FT-diesel will result in PM emission reduction which is not shown here
- PM emissions are generated primarily in combustion applications
- The main avenue to reduce biomass fuel chain emissions is the use of state-of-the-art engines and combustion turbines with reduced PM generation capability for biomass harvesting and transportation
- The main generator of PM emissions is within the fuel processing gate which use diesel engines which can be reduced with the use of more state-of-the-art equipment



Particulate matter is generated mostly at the vehicle for compression ignition engine vehicle options.

Air Emissions of Sample Fuel Options
Particulate matter emissions, grams per mile driven

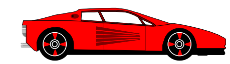
Emissions of a gasoline fuel chain = 0.005 gm per mile driven
Emissions of a reformulated gasoline fuel chain = 0.005 gm per mile driven
Emissions of a petroleum diesel fuel chain = 0.044 gm per mile driven



The use of diesel engines at processing plants accounts for the bulk of the emission for the ethanol cases.

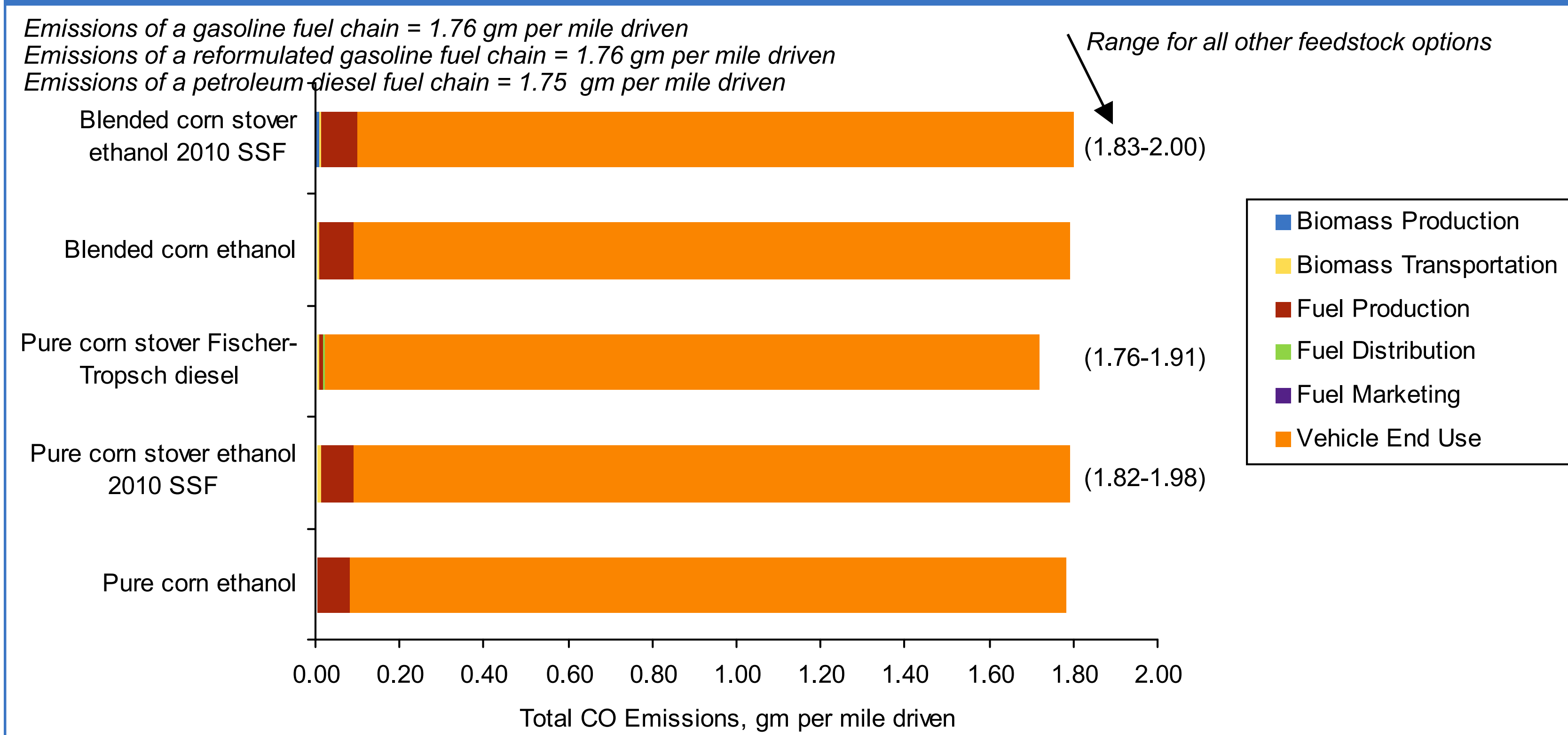
CO emissions are predominately generated in the end use step at the vehicle. Emissions are comparable to petroleum based chains.

Assumptions and Methodology	• CO emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass, and evaporative emissions at the fuel pump • The vehicle emissions of CO are set to the 50,000 mile durability ULEV standards for 2001-2006 model year for all passenger cars and light-duty trucks (0-3750 lbs LVW) • It is assumed that the engine will be designed to meet the emission standard regardless of the fuel used; therefore all chains have the same emissions per mile driven for the end use step • The emission factors used for diesel engines used in biomass production, biomass transportation, and engines used at the processing plant use 50/50 emissions which represent that an average of 1/2 of the engines used are state-of-the-art and 1/2 are uncontrolled
Comments	• For agricultural residues & energy crops, many biomass fuel types are possible. Corn stover is used here as an example. For the remaining solid biomass feedstocks (e.g., woody biomass, wheat straw, switchgrass), the range of total emissions (i.e., all value chain steps) is given on top of the detailed breakdown for corn stover • The CO emissions shown are generated primarily in the end use step in the vehicle engine
Conclusions	• Biomass derived fuels will offer comparable carbon monoxide emissions compared to petroleum-derived fuels • Carbon monoxide is mainly generated in the vehicle step of the fuel chain. Vehicle performance will most probably be designed to meet relevant emission standards. Differences among various fuels type will be negligible in the vehicle step



A significant fraction of the carbon monoxide is generated at the vehicle.

Air Emissions of Sample Fuel Options
Carbon monoxide emissions, grams per mile driven



Biomass fuels can produce solid wastes and water effluent; water use and treatment may be an issue in some geographical areas.

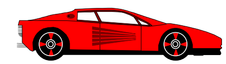
Solid Waste

- Solid wastes issues are likely to be manageable for projected single plant sizes
- Solid waste is likely to be less an issue for biofuels compared to biopower applications
- Solid waste production and disposal may be an issue for fermentation based processes which generate waste biomass in the form of organic cell mass materials
- Ash production is may still be an issue since most biomass biofuel plants will use lignin and cell mass as fuel for on-site power generation
  - Biomass ash is generally non-toxic and is capable of being used, and even sold, for beneficial purposes (e.g., fertilizer)

Effluent Waste

- Effluent can originate from a number of sources, but is usually preventable
  - Effluent from fermenters (ethanol production) is typically filtered and recycled, and the solids are de-watered for handling as solid wastes
  - Facilities may have to monitor or control storm and wash-down runoff, which may contain substances leached from biomass storage and handling areas
  - Effluent can contain suspended solids and BOD[1], but toxicity is not usually a serious concern
- Fischer-Tropsch based processes generate water which may be treated and used for irrigation of the biomass feedstock
- Water requirements for mega-scale ethanol plants may be an issue in semi/arid geographical areas

[1] Biological Oxygen Demand, which is a measure of the potential of organic wastes to compete with aquatic life for dissolved oxygen

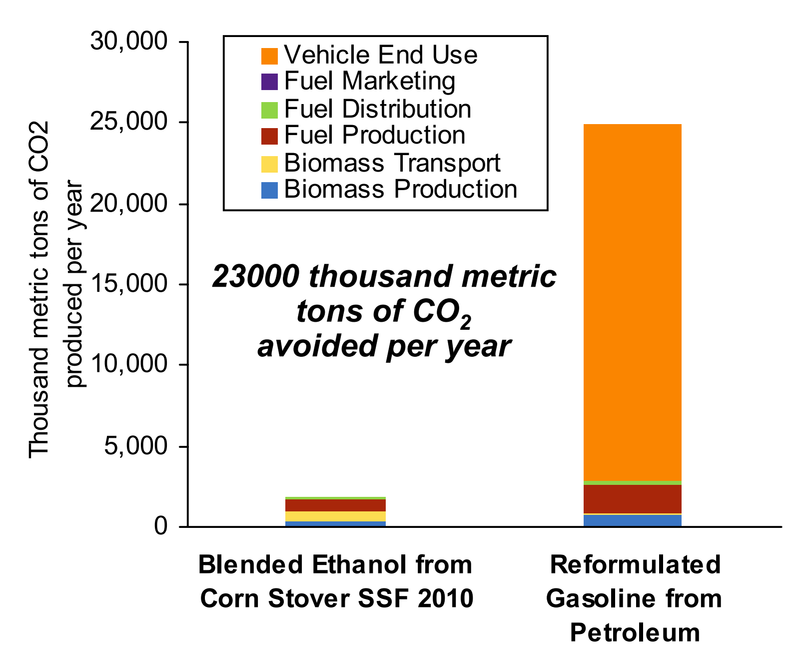


Blended cellulosic ethanol is used to illustrate the possible environmental benefit of biomass fuels, if deployed aggressively.

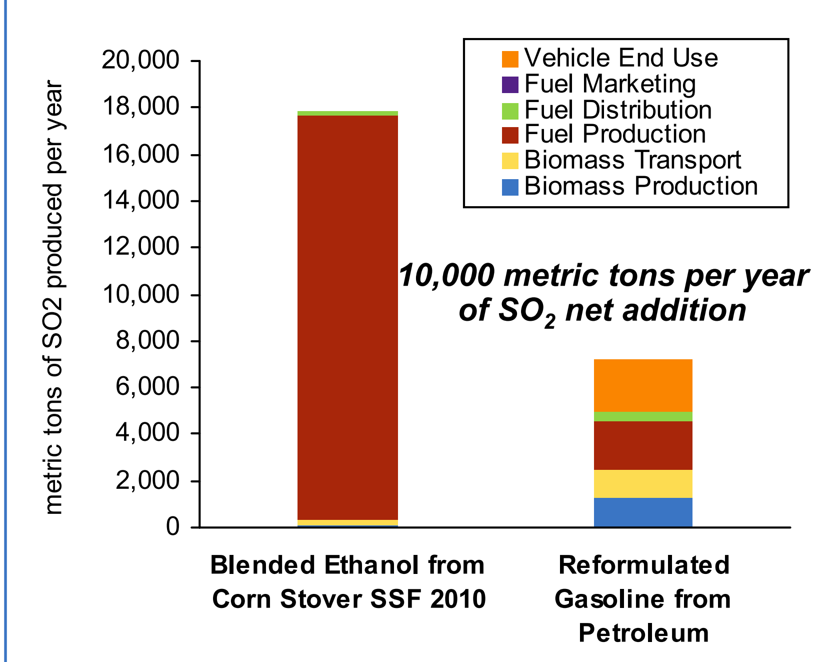
- Blended cellulosic ethanol has the potential to result in a aggressive growth of biomass derived fuels (to a level of 334 million GJ per year of fuel; 3.4 billion gallons of ethanol)
- Corn stover was taken as an example as its potential use alone could reach the biofuels aggressive goal (334 million GJ of fuel)
- There is an excess of corn stover over that which would be required to manufacture the ethanol for blending
- The charts that follow use a total of 50,000 thousand tons of stover
- The resulting possible total impact of cellulosic ethanol provides an illustration of potential environmental benefits of biofuels
- The biomass fuels are compared with the equivalent gasoline-related emissions

Blended ethanol has significant carbon dioxide reduction benefits. Even though biofuels are low in sulfur, the total chain emissions are comparable to petroleum fuels.

Carbon Dioxide Avoided per Year
Thousand Metric tons for 334,000,000 GJ/yr

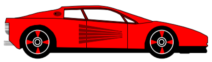


Sulfur Dioxide Increase
metric tons for 334,000,000 GJ/yr



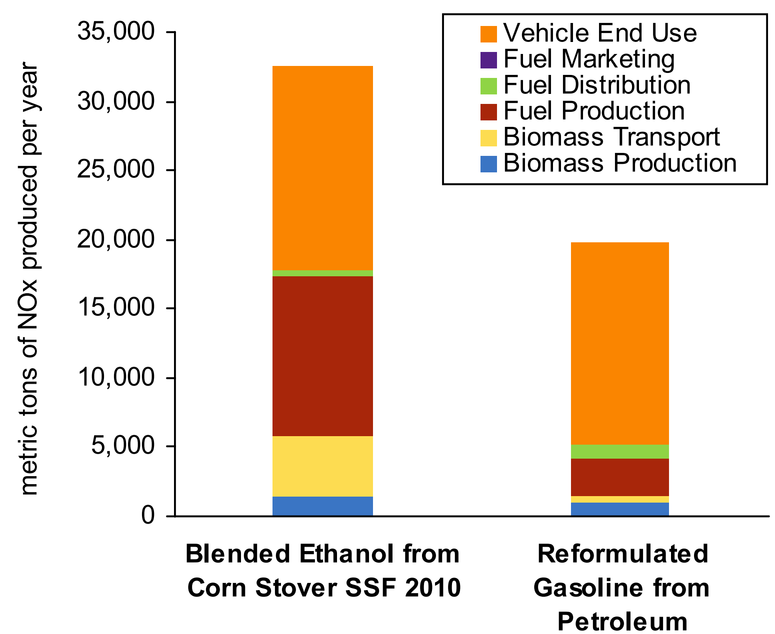
1. The Emissions shown produce a total of 334,000,000 GJ of fuel per year using a total of 50,385 thousand tons per year of blended ethanol from corn stover using NREL SSF 2010. Only the emissions associated with ethanol are shown. Fuel economy of 0.22 miles/MJ fuel.

Reduction of diesel engine use in fuel processing/production may reduce total biofuel chain sulfur emissions.



Benefits in NOx reduction are negligible for cellulosic ethanol when the emissions control on the ethanol plant are comparable to refinery practice.

Nitrogen Oxides Increase
metric tons for 334,000,000 GJ/yr



12,500 metric tons per year of NO_x Net addition

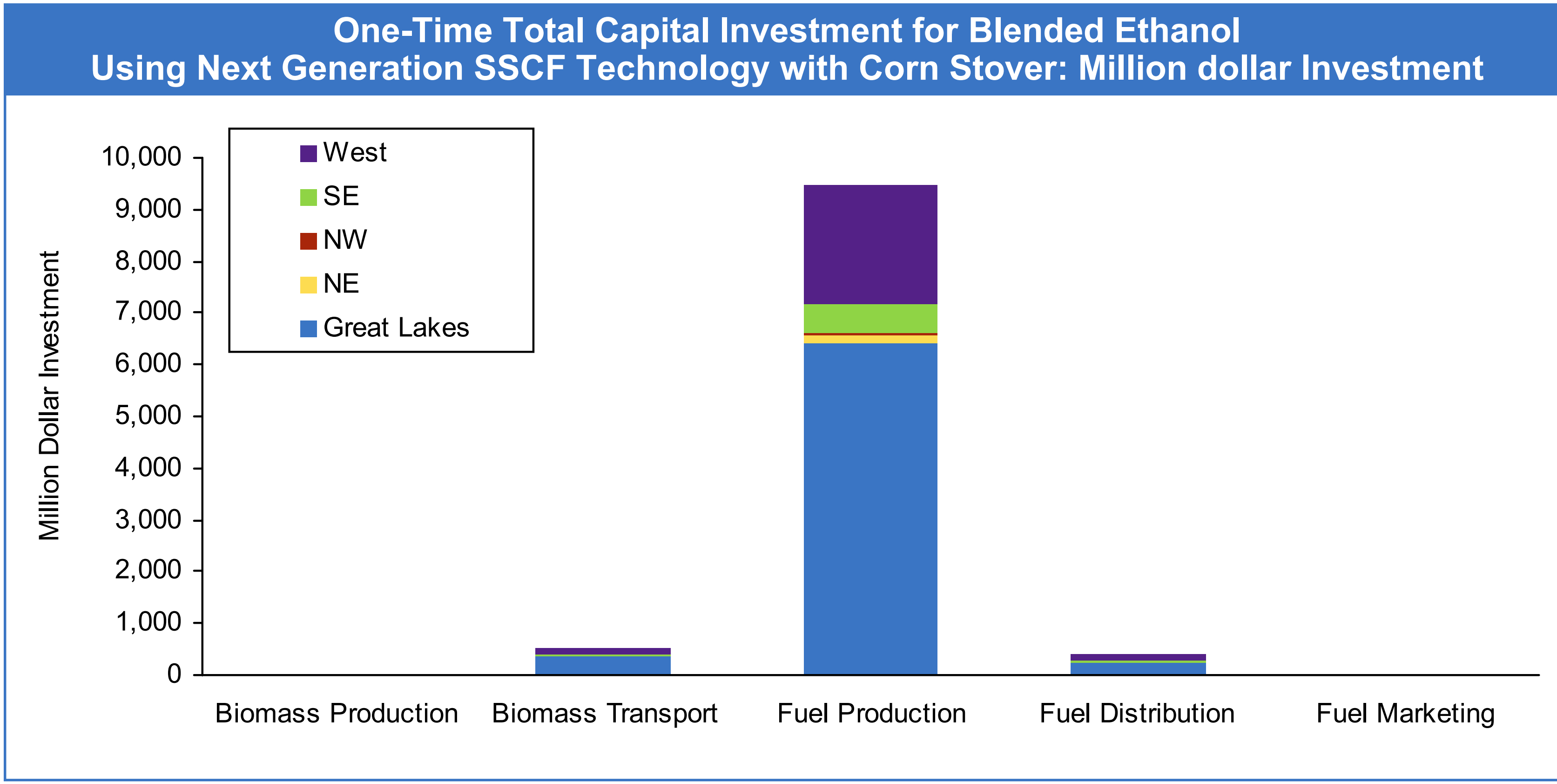
1. The Emissions shown produce a total of 334,000,000 GJ of fuel per year using a total of 50,385 thousand tons per year of blended ethanol from corn stover using NREL SSF 2010. Fuel economy of 0.22 miles/MJ fuel. Only the emissions associated with ethanol are shown.

Actual vehicle NOx emissions were assumed to be the same for ethanol as for the gasoline chain, dictated by relevant vehicle emission standards.

The method of analysis has implications in the conclusions for possible economic impact of accelerated biomass use for fuel.

- We assumed that the capital investment associated with biomass production is contained in the feedstock price
- One weakness of this method is that it does not account for any additional investment of equipment that is needed to collect the biomass not currently harvested
- The same thought experiment used to illustrate environmental impacts is used here to illustrate the possible impacts of accelerated biomass use using corn stover cellulosic ethanol for blending
- The investments shown produce a total of 3.4 billion gallons of ethanol (334 million GJ per year) using a total of 50,000 thousand tons per year of corn stover

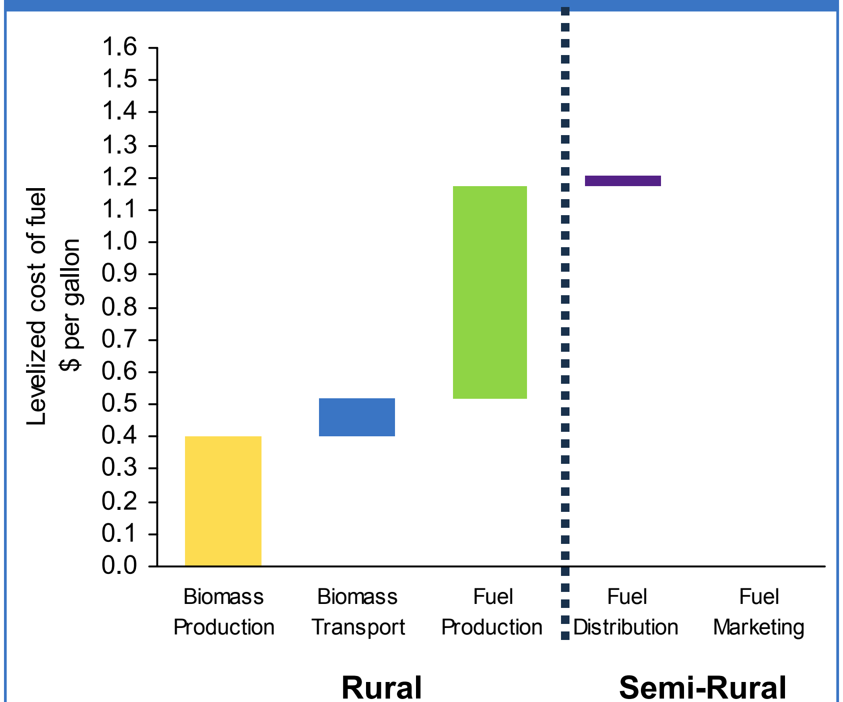
In terms of one-time investment, the bulk of the capital required may be in processing plants for cellulosic ethanol.



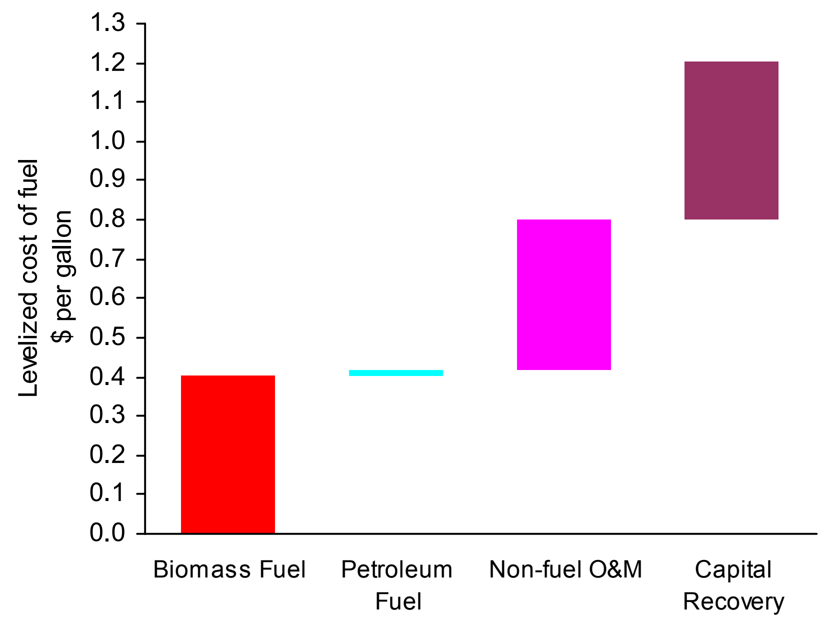
1. The investments shown produce a total of 334,000,000 GJ of fuel per year using a total of 50,385 Ktons per year of blended ethanol from corn stover using NREL SSF 2010
2. The capital investment associated with biomass production is assume to be contained in the feedstock cost.

Value creation for blended cellulosic ethanol is comparably split between actual production of biomass and manufacture of the fuel.

Corn Stover Blended Ethanol
Next Generation SSCF Technology
Levelized Cost of Fuel, $ per gallon



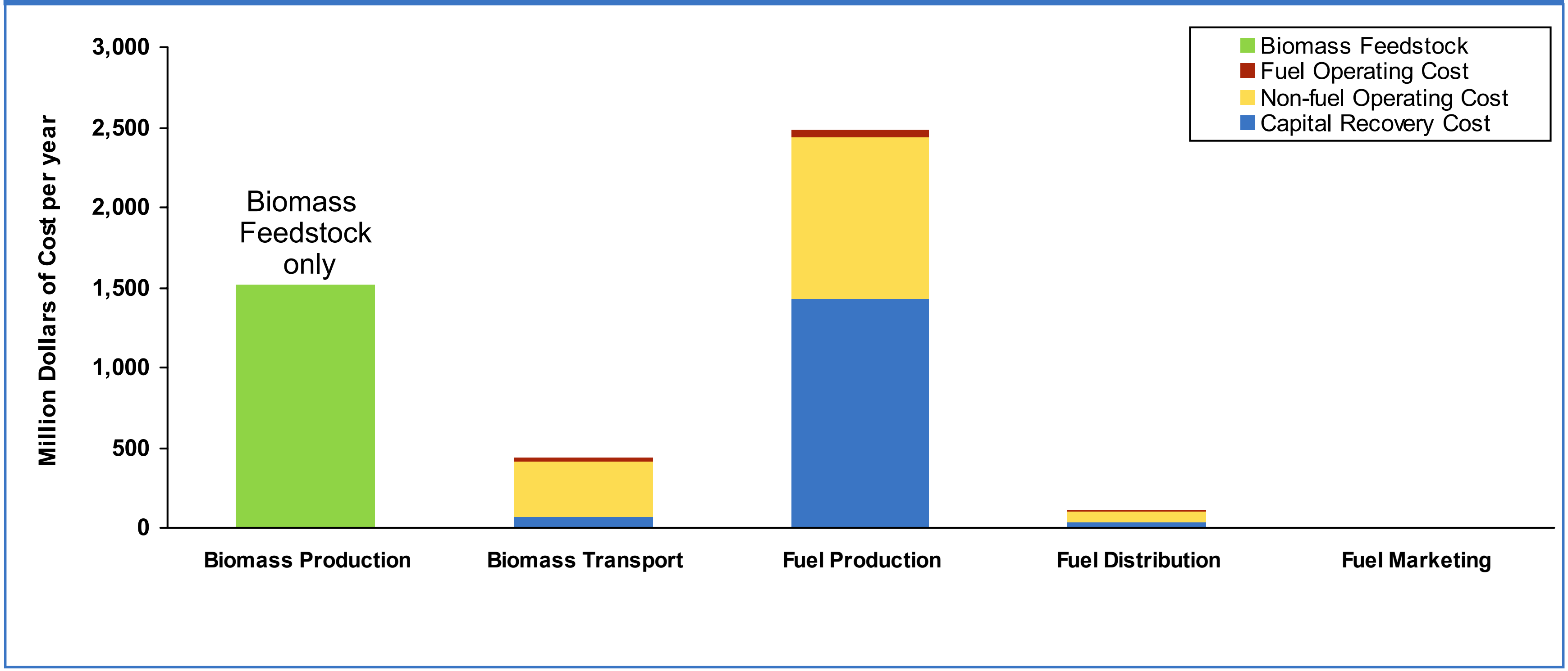
Corn Stover Blended Ethanol
Next Generation SSCF Technology
Levelized Cost of Fuel, $ per gallon



1. Capital recovery cost per year are a 13% per year for biomass transport investment and 15% for fuel production investment, 9% for fuel distribution investment, and 25% for fuel marketing. The capital recovery for biomass production is included in the price for biomass.
2. The fuel operating cost for biomass production is solely the cost of the biomass. The capital, non-fuel operating, and petroleum fuel costs in biomass production are incorporated into the price for biomass
3. The feedstock cost of corn stover is $30 per ton.

The annual costs are comparable between the cost of the biomass and the cost of operating the processing plants for cellulosic blended ethanol.

Blended Ethanol from Corn Stover Using Next Generation SSCF Technology
Cost of Total Fuel Chain, $Millions/yr



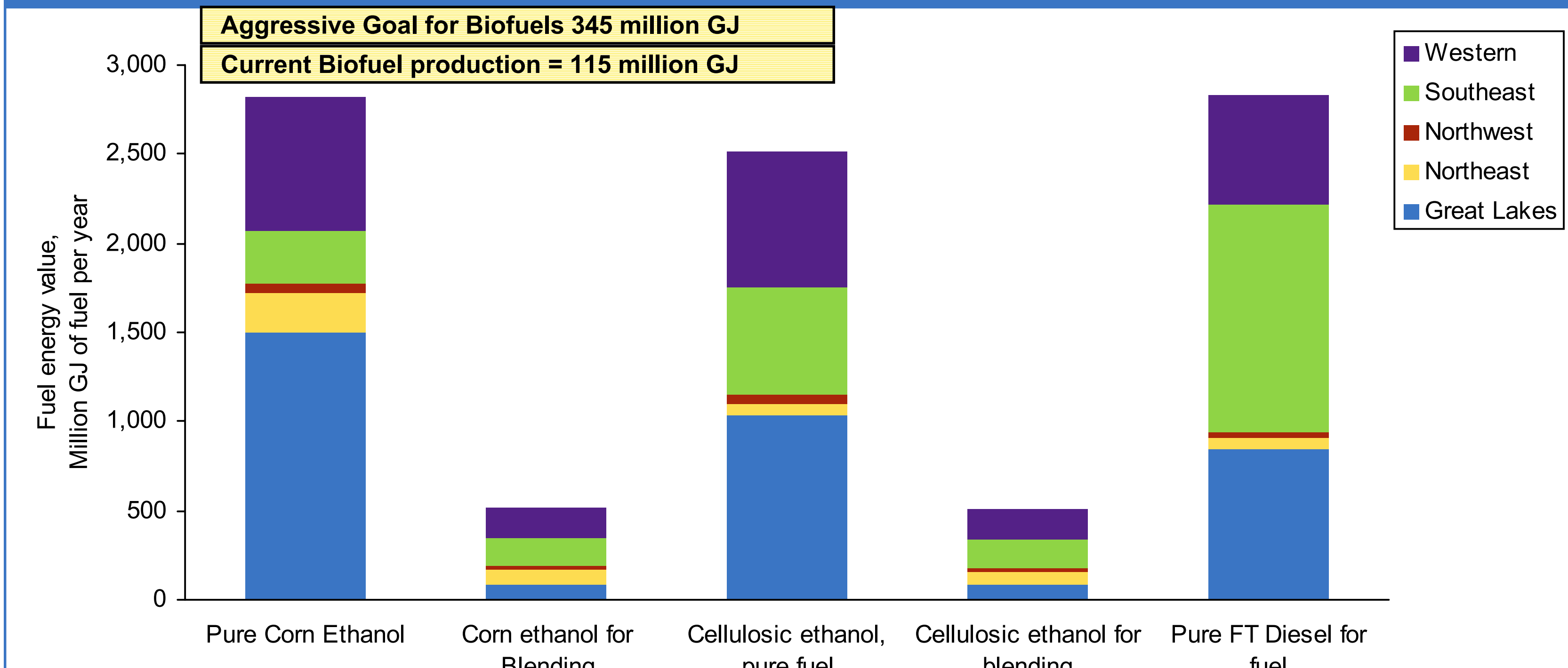
1. Capital recovery cost per year are a 13% per year for biomass transport investment and 15% for fuel production investment, 9% for fuel distribution investment, and 25% for fuel marketing.
2. The fuel operating cost for biomass production is solely the cost of the biomass. The capital, non-fuel operating, and petroleum fuel costs in biomass production are incorporated into the price for biomass
3. The feedstock cost of corn stover is $30 per ton.
4. The investments shown produce a total of 334,000,000 GJ of fuel per year using a total of 50,385 thousand tons per year of blended ethanol from corn stover using NREL SSF 2010

Cellulosic ethanol as a blending agent is a probable avenue to increase use of biomass-derived fuels and could lead to aggressive growth of biomass for fuels.

- Pure fuels represent the largest potential opportunity for the use of biomass fuels
- However, the premium associated with pure biomass fuels is projected to be at least 100 percent compared to projected petroleum fuels (exclusive of any incentives)
- Although not shown, FT diesel from biomass could be used as a blending agent (providing a zero sulfur, zero aromatic blending stock)
- Provided that low cost biomass feedstock can be used, cellulosic ethanol for blending could provide a major avenue to increase the use of biomass derived fuels
- Corn ethanol also is a continuing option for a blending stock
- Significant demands for ethanol for blending may be highly dependent upon the demand for oxygenates for reformulated fuels and the phasing-out of MTBE

Pure fuels represent the largest opportunity; however, the projected costs suggest that blended fuels are more likely in the near to mid-term.

Maximum Biofuel Market



1. The bars represent using the entire resource to generate fuel.
2. Cellulosic ethanol includes corn stover, wheat straw, switchgrass, and poplar using the 2010 NREL SSF technology for ethanol production.
3. FT diesel (Fischer-Tropsch) includes corn stover, wheat straw, switchgrass, and poplar.
4. Ethanol fuel blends are on a volume basis at 10 percent by volume
5. The following energy values have been used for the fuels: Ethanol 88.6 MJ per gal.; FT diesel 138.4 MJ per gal.
6. Corn ethanol for blending is not resource limited, but demand limited in all regions
7. Cellulosic ethanol for blending is demand limited in all regions except the Northeast.

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Bioproducts can offer significant benefits, though not in absolute terms, but at a modest ultimate cost to the nation.

- CO_2 emissions of bioproducts could offer significant benefits but the absolute amount is somewhat limited by the size of chemicals markets
- Criteria pollutant emissions are not strongly impacted by the implementation of bioproducts
- The solid and water effluent waste is likely to have the same issues as for cellulosic ethanol implementation and is expected to be manageable
  - Solid wastes are expected to be biodegradable and usable as fuel (e.g. Cell mass)
  - Water will contain suspended solids and toxicity is not a serious concern
  - Water use for processing (especially for fermentation) may be a concern in arid or semi-arid regions
- Production As costs for bioproducts appear to be approaching those of conventional products, the cost of implementation of bioproducts could eventually be quite low
- Bioproducts will primarily off-set products now produced from partially imported petroleum, thus the cost of bioproducts, will be off-set partially by increased economic activity and tax revenues
- Most of the economic value-added in the production of bioproducts is added in the conversion plant, which is most likely located near existing chemical plants

In our methodology we did not consider the post-consumer fate of the products, resulting in the maximum impact of bioproducts.

- For carbon dioxide emissions, the methodology assumes that carbon is sequestered in the final product
  - This is equivalent to the product being land-filled with the carbon removed from the carbon cycle
  - This analysis does not take into account the product's biodegradability
  - This *does not* take into account the final product being "recycled" or recovered for its energy value
- The value chain analyzed ends at the primary processing plant gate
  - This has implications for the other emissions analyzed (e.g. SO_2, NOx, hydrocarbons, CO and PM)
- The analysis did not account for downstream pieces of the value chain that will generate additional emissions for neither the bioproduct nor the conventional product
  - Transportation and distribution of the primary product if applicable
  - Further processing the primary product to form the final consumer product
  - Any necessary processing to form a derivative product
  - Associated transportation, distribution, and marketing of the final product form
- The level of information available has implications in emission estimation
  - Most processes in this analysis used grid average electricity (and its associated emissions)
  - In reality, plant integration could shift to onsite power production to reduce grid demand (with possibly lower net emissions)

This analysis is not a product life cycle analysis and should not be interpreted as such.

Air emissions were estimated and included those associated with biomass production & transportation and processing up to the primary plant gate.

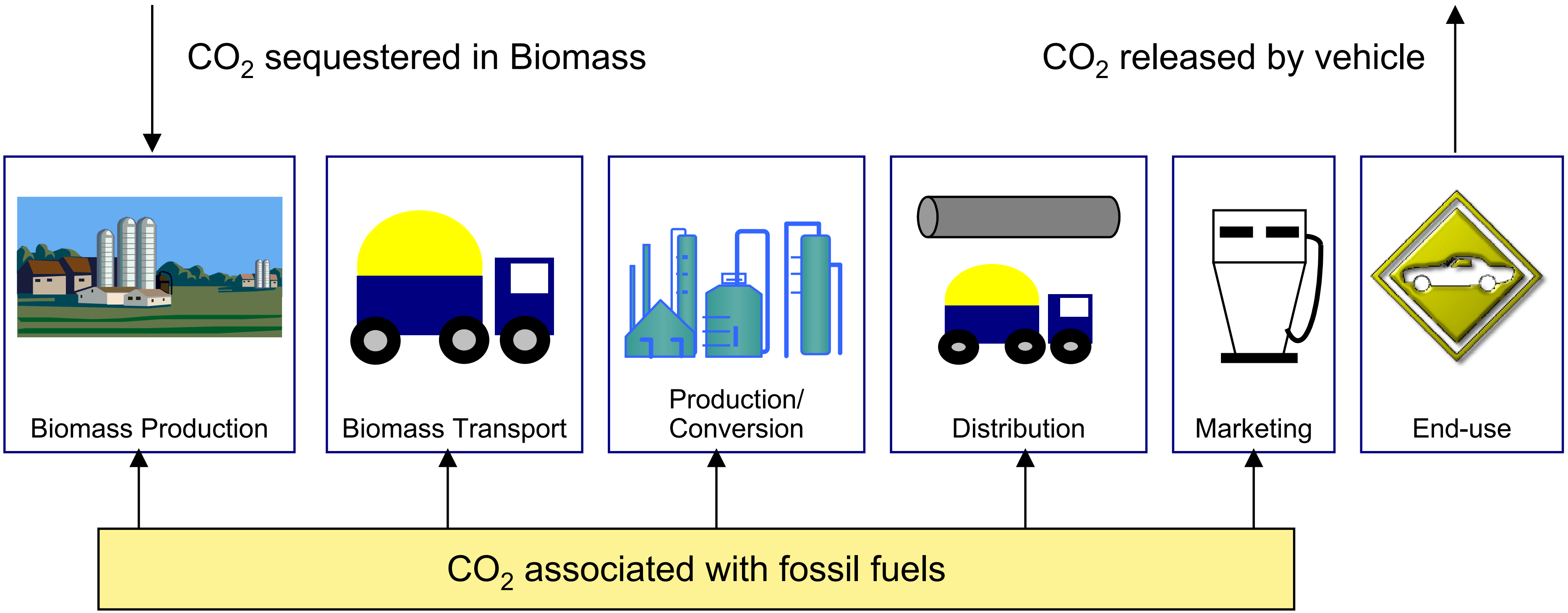
- Emissions associated with biomass production are included in the analysis
  - Most emissions are associated with planting and harvesting the biomass
  - Emissions with fertilizer use are also included
- The analysis assumes that on average biomass transportation to the processing plant involves 50-mile one-way trips
  - Emissions associated with diesel trucks are included
- The plant processing emissions are associated with three main components
  - Diesel engine use for onsite biomass handling contribute the bulk of the emissions
  - Onsite power production particularly for waste boilers and tail gas combustion
  - Emissions associated with average industrial grid mix of electricity
- For the processing plants, all equipment except diesel engines were assumed to be state-of-the-art with the associated best available control technology
- Diesel engine use within the plant gate was assumed to be a 50/50 mix of best available and uncontrolled engines

The premise is carbon in the final product is “sequestered”; essentially the product is land-filled so that the carbon does not re-enter the carbon cycle.

The diverse nature of products and the complexity of the various value chains makes it difficult to use a common baseline for comparison.

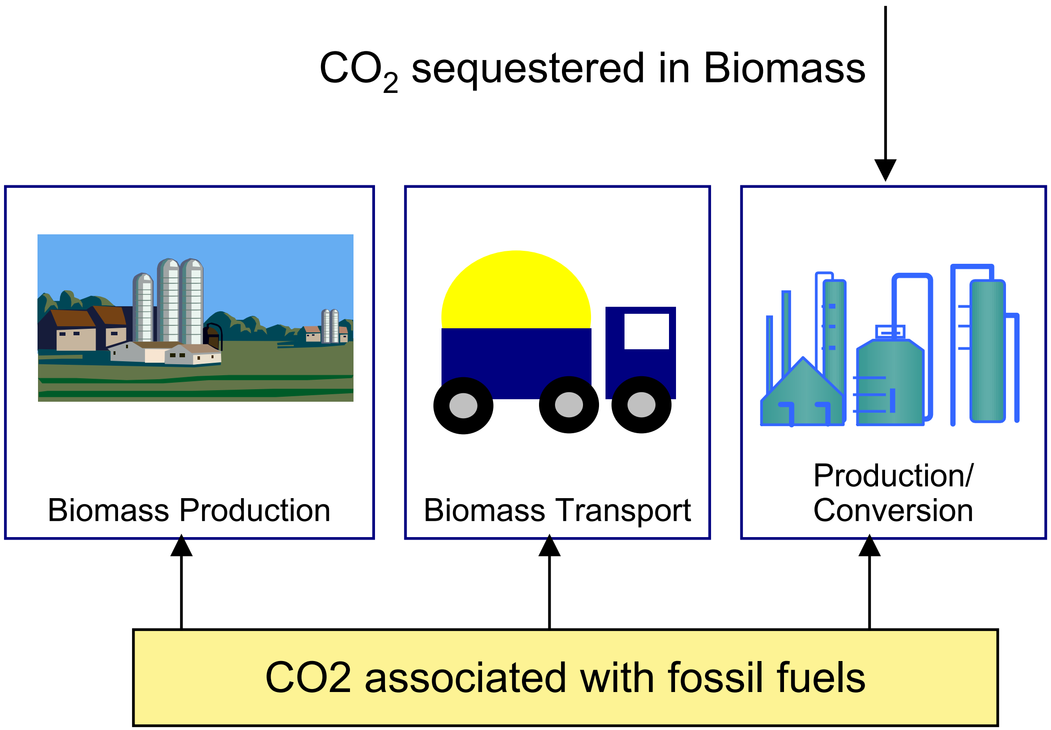
- We used sample products which represent a range of those obtained with current promising processing technology
  - Lactic acid and 1,3-propanediol from fermentation of starch feedstocks
  - Phenolics and levoglucosan from pyrolysis of a variety of woody cellulosics
  - Naphtha obtained via biomass gasification and Fischer-Tropsch synthesis
- Emissions were estimated to the primary plant gate and do not contain the associated emissions for a number of subsequent value chain steps
  - Distribution of the raw product
  - Subsequent processing of the raw product to make the final end product (e.g. polymer synthesis of monomers, blow-molding of the polymer to make the final part)
  - Distribution and marketing of the final products
  - Emissions associated with end use
- We took as an example, emissions from two fossil derived "building blocks" as a comparison (to the primary plant processing gate)
  - Methanol obtained from natural gas
  - Liquefied petroleum gas (LPG) from petroleum

For fuels, the CO_2 sequestered in the biomass is assumed to equal the CO_2 released by the vehicle.



Only the CO_2 emissions associated with fossil fuels are incorporated in the results.

For products, the CO_2 sequestered in the biomass is credited to the product in the product conversion step.



The CO_2 emissions associated with fossil fuels and the sequestering of CO_2 in the product are incorporated in the results.

Fully integrated bioproduct plants, part of a biorefinery concept, are likely to have reduced CO_2 emissions and may be an avenue for GHG reduction.

Assumptions and Methodology

- CO_2 emissions from the utilization of any biomass material as a fuel for engine use or power generation is assumed to be zero (closed-loop carbon cycle)
  - CO_2 emissions occur when other fuels and materials (e.g., chemical fertilizers) are used to grow, harvest, transport and process the biomass
- CO_2 emissions from any degrading of the final product itself are not included
- The results shown are estimated primary plant gate emissions and do not include those emissions from downstream portions of the value chain such as derivative manufacture, product formulation, distribution and marketing
- It is assumed that the product is essentially land-filled, effectively sequestering the carbon contained in the product

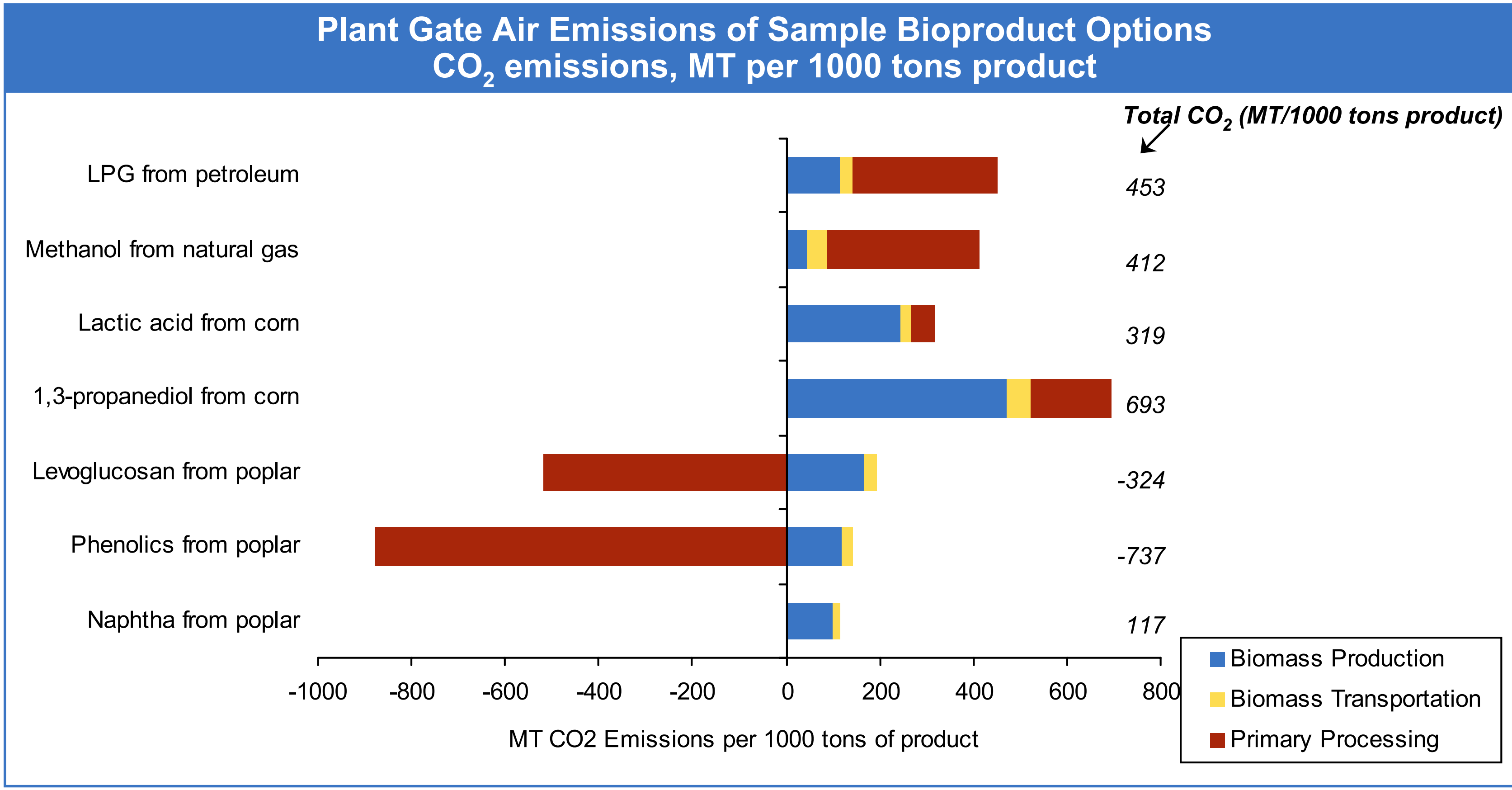
Comments

- For agricultural residues & energy crops, many biomass feedstock types are possible. Woody biomass such as poplar and starch feedstock are used here as an example
- The fermentation results are incomplete because they do not contain the associated emissions to make the starch from the corn. The fermentation emissions contain those associated with growing and transporting the corn to the processing site. Emissions associated with the actual fermentation and clean-up steps are included
- The CO_2 emissions shown are generated primarily from grid average electricity and fossil fuels required (mostly diesel fuel for harvesting the biomass, and transporting the biomass to the processing plant and internal plant requirements). The processing plant requirements are mainly for moving the biomass around the plant within the plant gate. All options used comparable diesel fuel on a biomass weight basis

Conclusions

- Bioproducts offer a route for GHG reduction. An assumption of the analysis is that the carbon contained in the product is effectively sequestered. There is a strong caveat in that subsequent portions of the value chain have not been considered in this analysis; this approximates the emissions generated up to the primary processing plant gate
- Fully integrated plants will likely reduce grid average electricity requirements which will likely lower associated emissions of CO_2
- Methods to reduce biomass handling/transport within the plant site will impact the carbon dioxide emissions for the entire chain
- Harvesting methods used will dramatically impact biomass fuel chain emissions which are directly attributed to fossil fuels used in harvesting

Carbon dioxide emissions are mainly associated with the use of diesel fuel in engines, especially in biomass production and grid electricity use.



Fully integrated bioproduct plants, part of a biorefinery concept, are likely to have reduced CO_2 emissions and may be an avenue for GHG reduction.

Bioproducts do not offer significant benefits for sulfur dioxide reduction compared to petrochemicals.

Assumptions and Methodology

- SO_2 emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass
- Sulfur dioxide emissions for naphtha (from FT synthesis) are lower primarily because sulfur-free FT-diesel is used within the plant processing gate to move the biomass within the processing plant
- The results shown are estimated plant gate emissions and do not include those emissions from downstream portions of the value chain such as derivative manufacture, product formulation, distribution and marketing

Comments

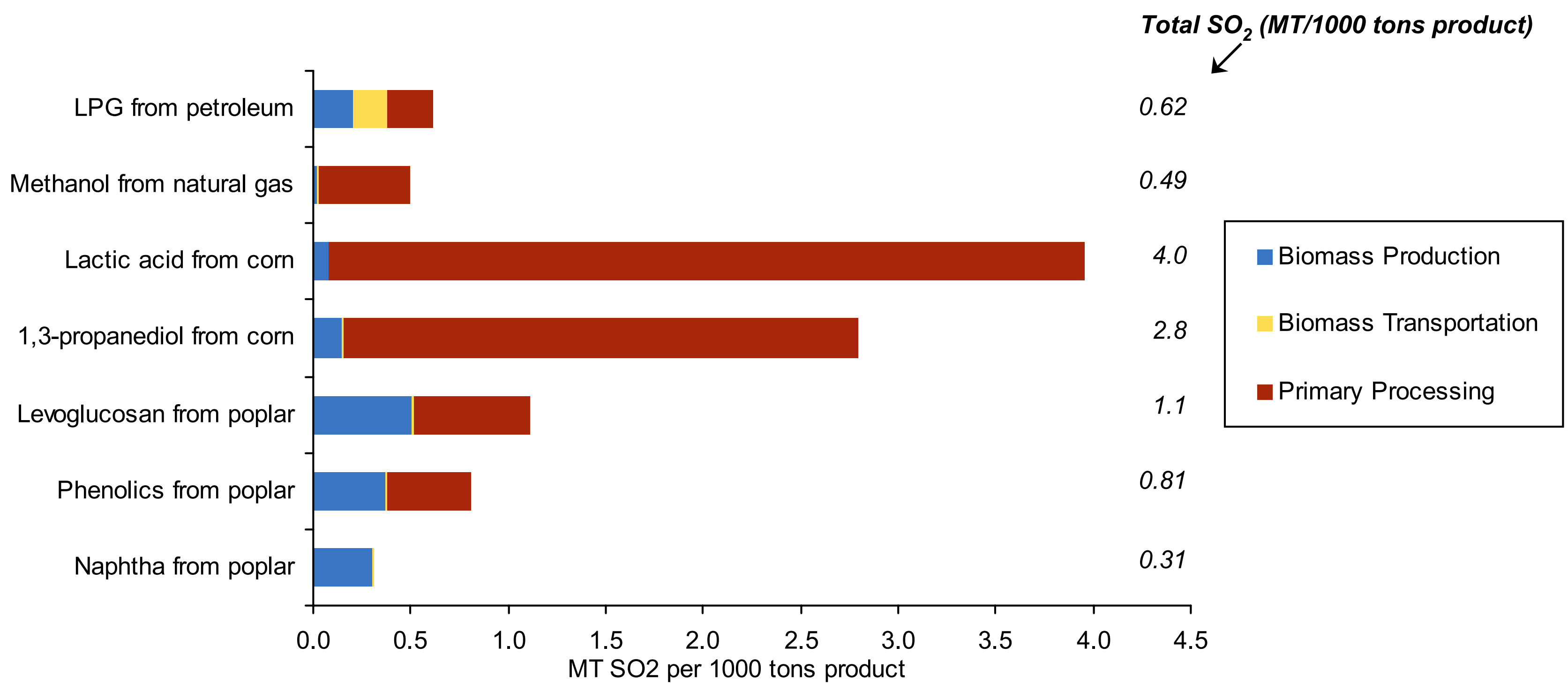
- For agricultural residues & energy crops, many biomass feedstocks are possible. Woody biomass such as poplar and starch feedstock are used here as an example
- The fermentation results are incomplete because they do not contain the associated emissions to make the starch from the corn. The fermentation emissions contain those associated with growing and transporting the corn to the processing site. Emissions associated with the actual fermentation and clean-up steps are included
- The SO2 emissions shown are generated primarily from grid average electricity use and fossil fuels required (mostly diesel fuel for harvesting the biomass, and transporting the biomass to the processing plant and internal plant requirements). The processing plant requirements are mainly for moving the biomass around the plant within the plant gate. All options used comparable diesel fuel on a biomass weight basis

Conclusions

- Bioproducts do not appear to offer sulfur dioxide reduction benefits. There is a strong caveat in that subsequent portions of the value chain have not been considered in this analysis; this approximates the emissions generated up to the primary processing plant gate
- Biomass transport and handling add little SO2 emissions
- The sulfur dioxide emissions shown are directly attributable to petroleum diesel use within the processing plant gate to move and handle the biomass within the plant site. Methods that reduce the amount of diesel fuel used for conveyors and fork lifts, for example will dramatically reduce chain emissions for the biomass fuels
- The assumed use of grid average electricity also contributes significantly to the sulfur emissions within the processing plant, especially for the fermentation-based products
- Fully integrated plants, part of a bio-refinery concept ,will likely have lower grid average electricity requirements and have lower associated emissions

The assumed use of grid average electricity contributes the bulk of the sulfur emissions in the processing plant step.

Plant Gate Air Emissions of Sample Fuel Options
SO_2 emissions, MT per 1000 tons product



Diesel fuel use contributes the bulk of emissions in the biomass production step. Naphtha processing used FT-diesel (sulfur-free) fuel.

Biomass products have comparable associated NOx emissions compared to typical petrochemicals.

Assumptions and Methodology

- NOx emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass
- The emission factors used for diesel engines used in biomass production, biomass transportation, and engines used at the processing plant use 50/50 emissions which represent that an average of 1/2 of the engines used are state-of-the-art and 1/2 are uncontrolled. Emissions from boilers and turbines at the processing plant were assumed to be state-of-the-art
- The results shown are estimated plant gate emissions and do not include those emissions from downstream portions of the value chain such as derivative manufacture, product formulation, distribution and marketing

Comments

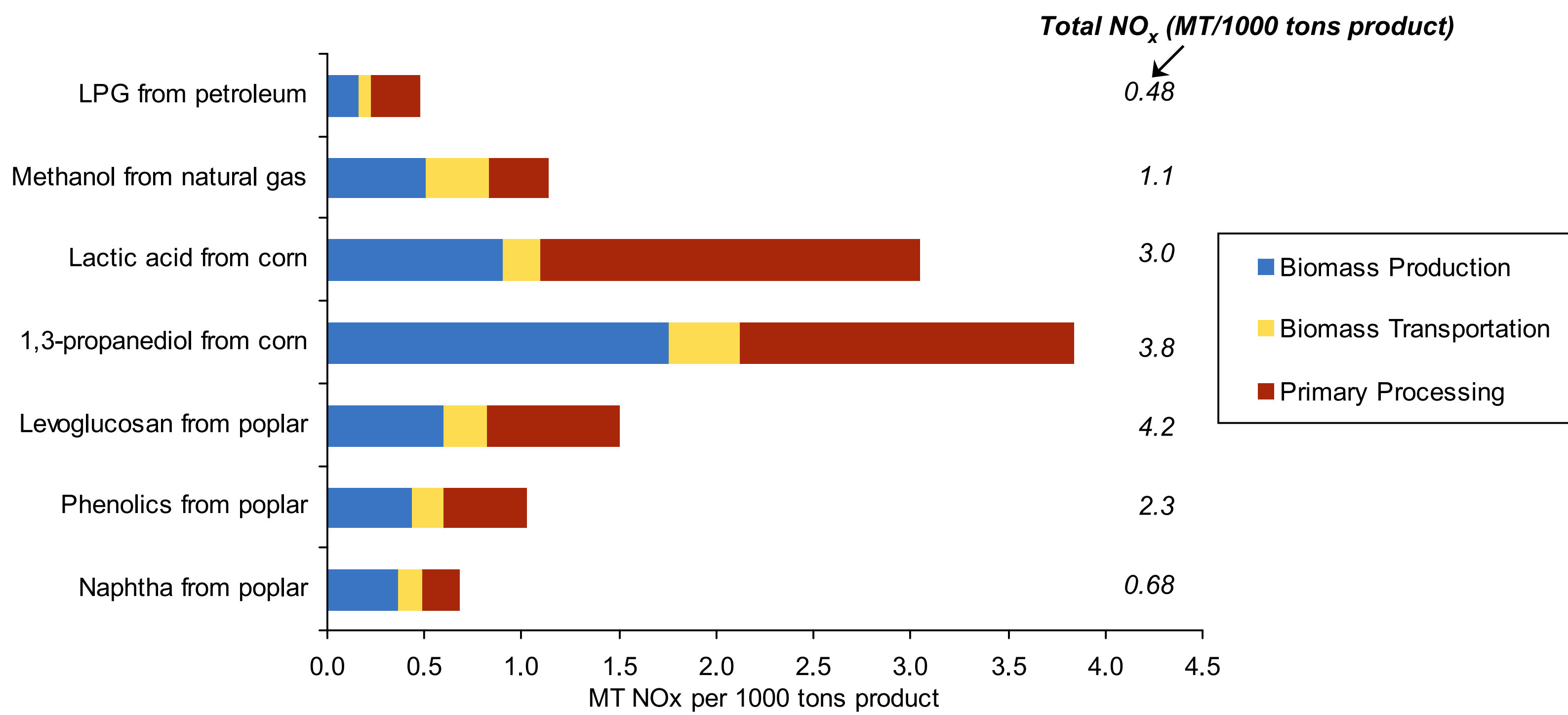
- For agricultural residues & energy crops, many biomass feedstocks are possible. Woody biomass such as poplar and starch feedstock are used here as an example
- The fermentation results are incomplete because they do not contain the associated emissions to make the starch from the corn. The fermentation emissions contain those associated with growing and transporting the corn to the processing site. Emissions associated with the actual fermentation and clean-up steps are included
- The processing plant fossil fuel requirements are mainly for grid average electricity use and diesel fuel for moving the biomass around the plant within the plant gate. All options used comparable diesel fuel on a biomass weight basis

Conclusions

- Biomass-only options do not appear to offer significant NOx emission reduction benefits. There is a strong caveat in that subsequent portions of the value chain have not been considered in this analysis; this approximates the emissions generated up to the primary processing plant gate
- NOx emissions are generated primarily in combustion applications
- The main avenue to reduce biomass fuel chain emissions is the use of state-of-the-art engines and combustion turbines with reduced NOx generation capability
- Fully integrated plants will likely use lower levels of grid average electricity than that used in this analysis. Lower emissions are likely, especially in fermentation-based processes (compared to that shown in this analysis)

NOx generation occurs about equally from the production of the biomass and the downstream processing steps.

Plant Gate Air Emissions of Sample Fuel Options
NO_x emissions, MT per 1000 tons product



For the fermentation-based processes, the bulk of the emissions in primary processing is associated with use of grid average electricity.

Net increase of emissions of methane is likely not an issue for bioproducts.

Assumptions and Methodology

- Methane emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass
- The emission factors used for diesel engines used in biomass production, biomass transportation, and engines used at the processing plant use 50/50 emissions which represent that an average of 1/2 of the engines used are state-of-the-art and 1/2 are uncontrolled. Emissions from boilers and turbines at the processing plant were assumed to be state-of-the-art
- The results shown are estimated plant gate emissions and do not include those emissions from downstream portions of the value chain such as derivative manufacture, product formulation, distribution and marketing

Comments

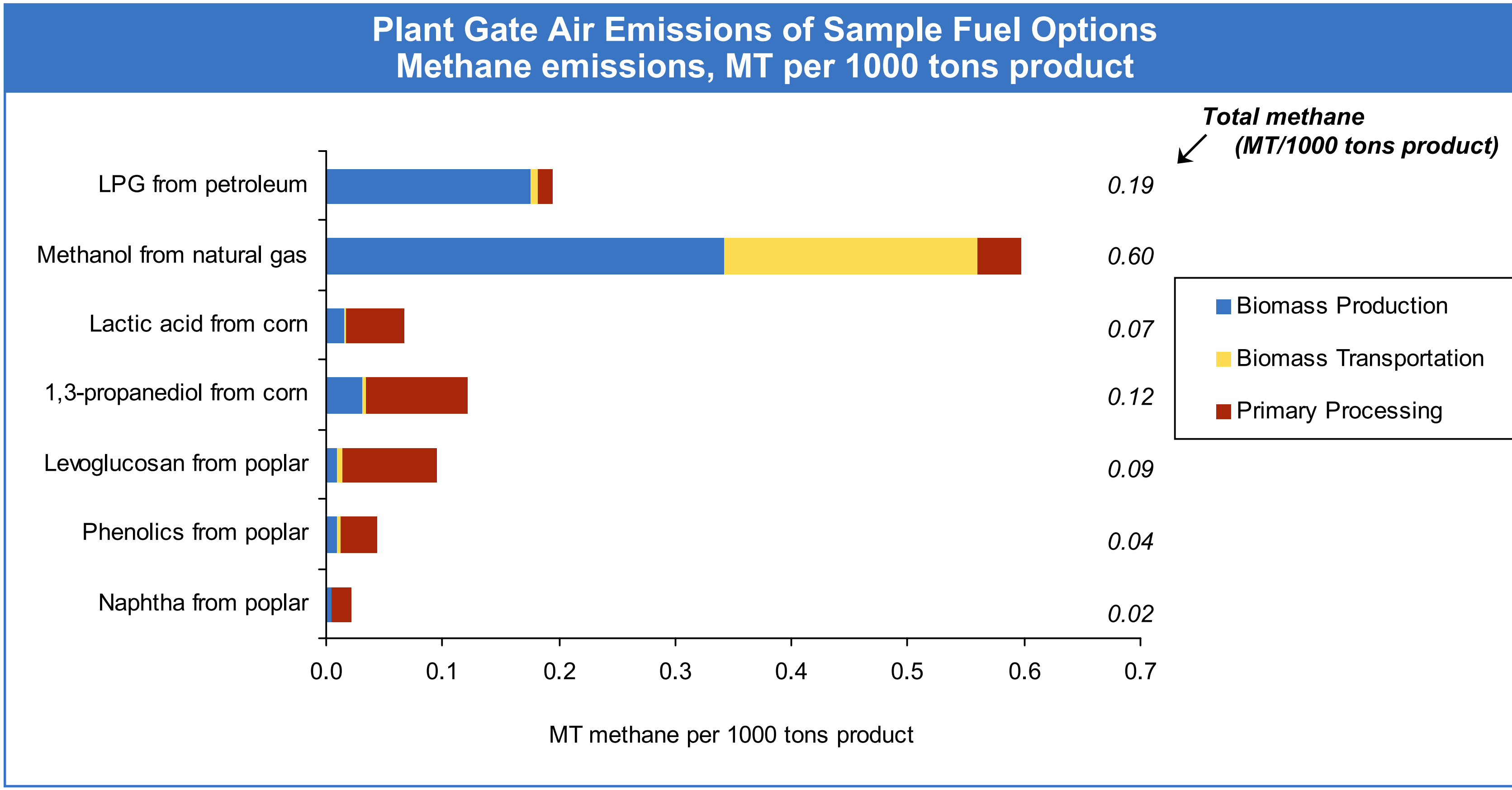
- For agricultural residues & energy crops, many biomass feedstocks are possible. Woody biomass such as poplar and starch feedstock are used here as an example
- The fermentation results are incomplete because they do not contain the associated emissions to make the starch from the corn. The fermentation emissions contain those associated with growing and transporting the corn to the processing site. Emissions associated with the actual fermentation and clean-up steps are included
- The processing plant fossil fuel requirements are mainly for moving the biomass around the plant within the plant gate. All options used comparable diesel fuel on a biomass weight basis

Conclusions

- Biomass-only options do not result in higher net methane emissions. There is a strong caveat in that subsequent portions of the value chain have not been considered in this analysis; this approximates the emissions generated up to the primary processing plant gate
- Methane emissions associated with biomass production/harvesting and biomass transportation to the processing plant are minimal

Most methane generation is expected in the primary processing step to make the product.

Bioproducts are likely to have comparable or lower methane emissions as for routes using petrochemicals.



Methane generation occurs mostly during the processing steps.

Nonmethane hydrocarbons emissions are likely to be comparable with that associated with petrochemical manufacture.

Assumptions and Methodology

- Nonmethane hydrocarbon (NMHC) emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass
- The emission factors used for diesel engines used in biomass production, biomass transportation, and engines used at the processing plant use 50/50 emissions which represent that an average of 1/2 of the engines used are state-of-the-art and 1/2 are uncontrolled. Emissions from boilers and turbines at the processing plant were assumed to be state-of-the-art
- The results shown are estimated plant gate emissions and do not include those emissions from downstream portions of the value chain such as derivative manufacture, product formulation, distribution and marketing

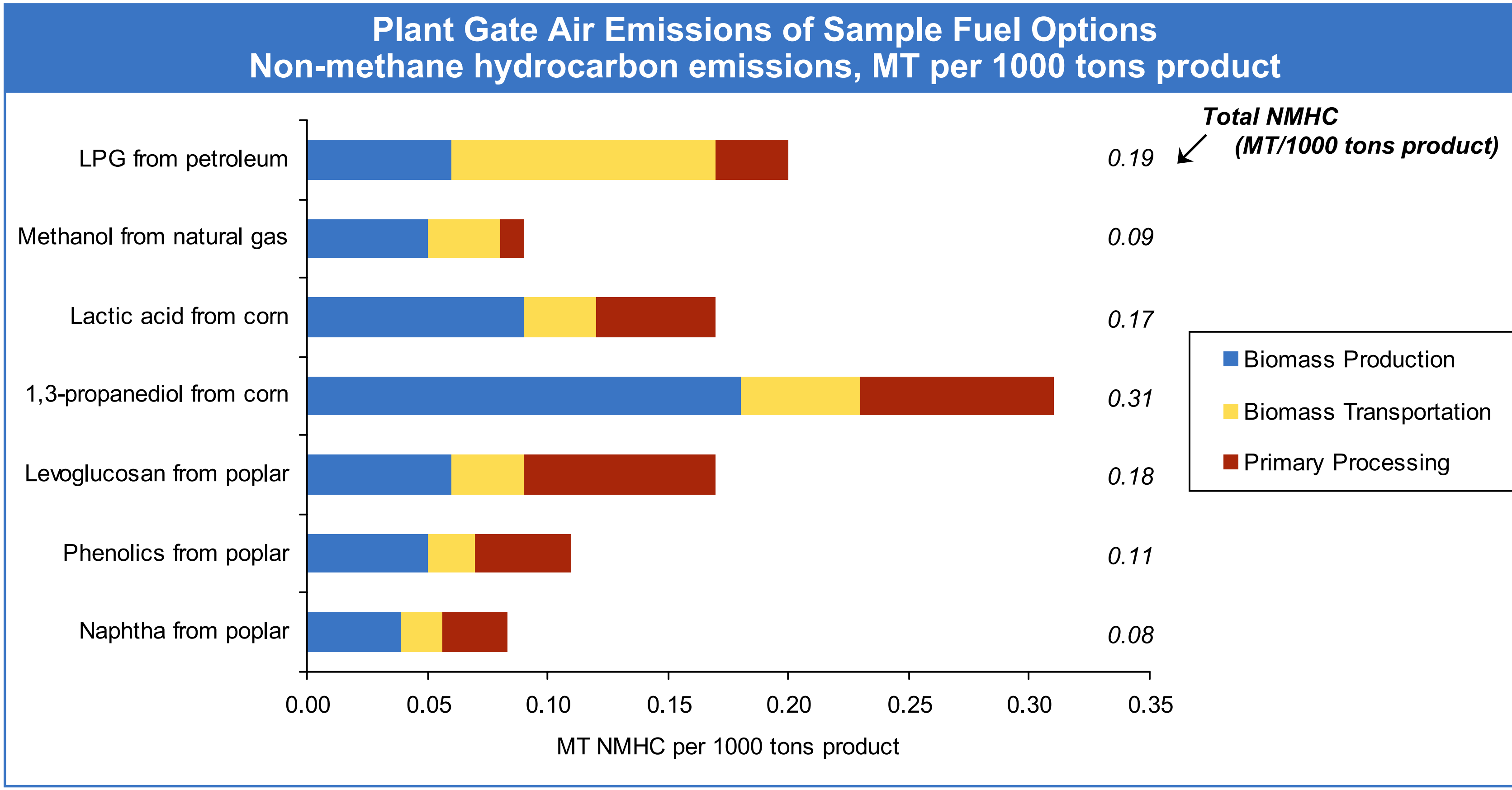
Comments

- For agricultural residues & energy crops, many biomass feedstocks are possible. Woody biomass such as poplar and starch feedstock are used here as an example
- The fermentation results are incomplete because they do not contain the associated emissions to make the starch from the corn. The fermentation emissions contain those associated with growing and transporting the corn to the processing site. Emissions associated with the actual fermentation and clean-up steps are included
- The processing plant fossil fuel requirements are mainly for moving the biomass around the plant within the plant gate. All options used comparable diesel fuel on a biomass weight basis

Conclusions

- Biomass-only options have comparable nonmethane hydrocarbon emissions as petrochemicals. There is a strong caveat in that subsequent portions of the value chain have not been considered in this analysis; this approximates the emissions generated up to the primary processing plant gate
- Diesel engine use both in biomass production/harvesting and primary processing contribute significantly to the generation of nonmethane hydrocarbon emissions

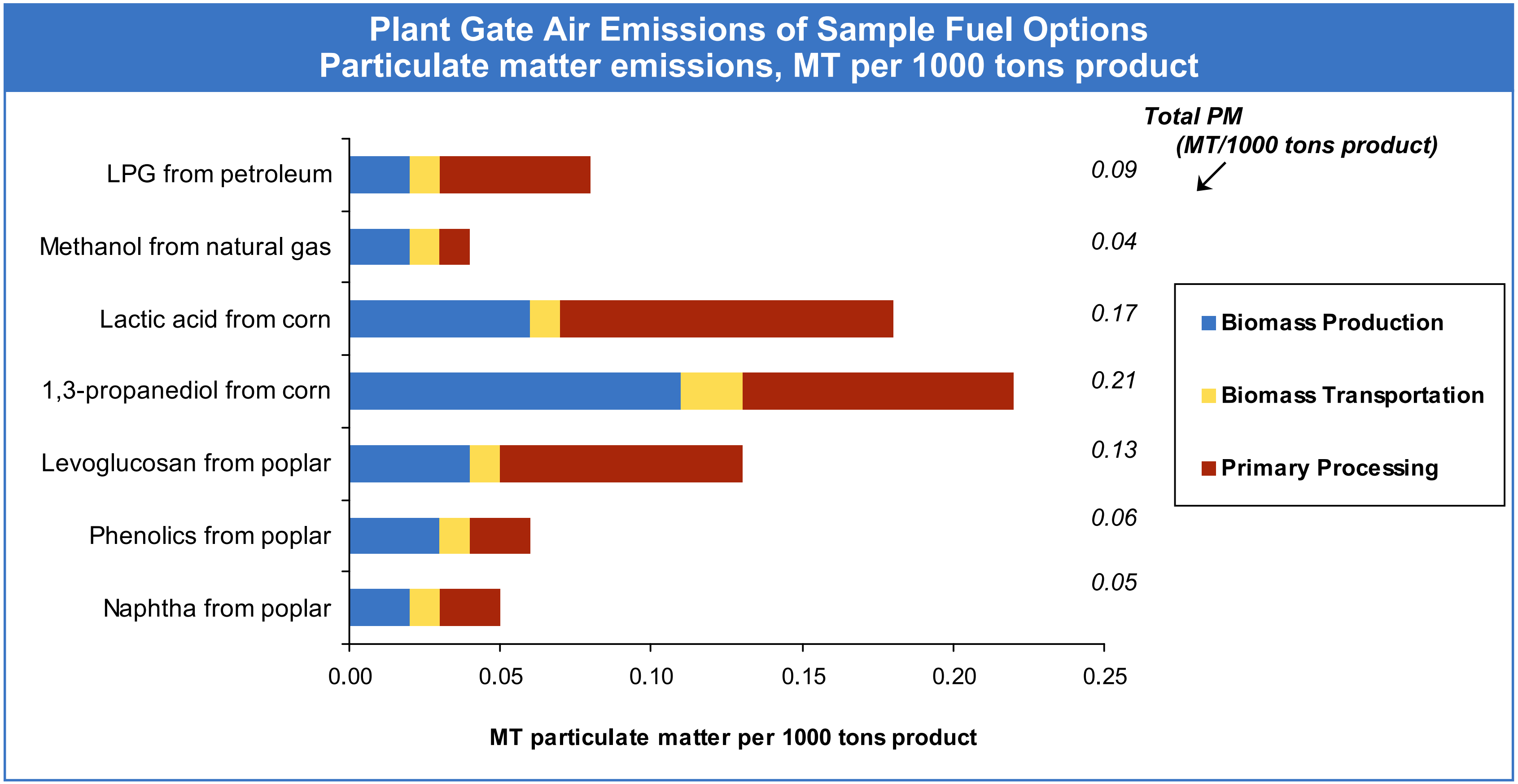
An important source of nonmethane hydrocarbon emissions are diesel engines used during biomass production.



Bioproducts will offer comparable PM emissions compared to petrochemicals when including those associated with biomass production.

Assumptions and Methodology	• Particulate matter emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass • The emission factors used for diesel engines used in biomass production, biomass transportation, and engines used at the processing plant use 50/50 emissions which represent that an average of 1/2 of the engines used are state-of-the-art and 1/2 are uncontrolled. Emissions from boilers and turbines at the processing plant were assumed to be state-of-the-art • The results shown are estimated plant gate emissions and do not include those emissions from downstream portions of the value chain such as derivative manufacture, product formulation, distribution and marketing
Comments	• For agricultural residues & energy crops, many biomass feedstocks are possible. Woody biomass such as poplar and starch feedstock are used here as an example • The fermentation results are incomplete because they do not contain the associated emissions to make the starch from the corn. The fermentation emissions contain those associated with growing and transporting the corn to the processing site. Emissions associated with the actual fermentation and clean-up steps are included • The processing plant fossil fuel requirements and its associated emissions are mainly for moving the biomass around the plant within the plant gate. All options used comparable diesel fuel on a biomass weight basis • The PM emissions shown are generated primarily from fossil fuels required (mostly diesel fuel) for internal plant requirements
Conclusions	• Biomass-only options have comparable PM emissions as petrochemicals. There is a strong caveat in that subsequent portions of the value chain have not been considered in this analysis; this approximates the emissions generated up to the primary processing plant gate • Diesel engine use both in biomass production/harvesting and primary processing contribute significantly to the generation of PM emissions. • PM emissions are generated primarily in combustion applications. The main avenue to reduce biomass fuel chain emissions is the use of state-of-the-art engines and combustion turbines with reduced PM generation capability for biomass harvesting and transportation

An important source of particulate matter emissions are diesel engines used during biomass production.



It is likely that bioproducts will provide comparable CO emissions as that associated with petrochemicals.

Assumptions and Methodology

- CO emissions occur both from the utilization of the biomass itself plus from the use of other fuels and materials (e.g., chemical fertilizers), which are used to grow, harvest, transport and process the biomass
- The emission factors used for diesel engines used in biomass production, biomass transportation, and engines used at the processing plant use 50/50 emissions which represent that an average of 1/2 of the engines used are state-of-the-art and 1/2 are uncontrolled. Emissions from boilers and turbines at the processing plant were assumed to be state-of-the-art
- The results shown are estimated plant gate emissions and do not include those emissions from downstream portions of the value chain such as derivative manufacture, product formulation, distribution and marketing

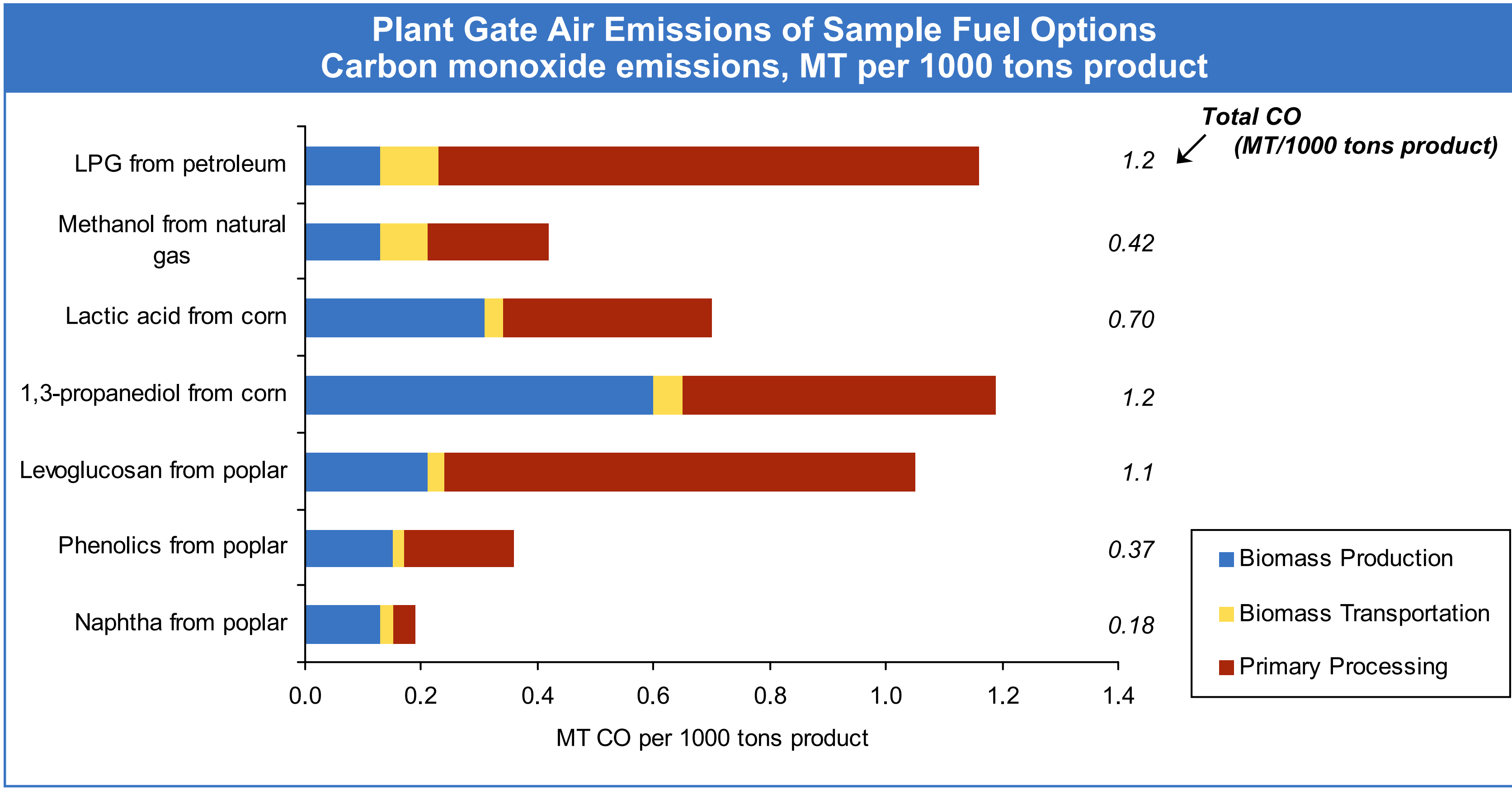
Comments

- For agricultural residues & energy crops, many biomass feedstocks are possible. Woody biomass such as poplar and starch feedstock are used here as an example
- The fermentation results are incomplete because they do not contain the associated emissions to make the starch from the corn. The fermentation emissions contain those associated with growing and transporting the corn to the processing site. Emissions associated with the actual fermentation and clean-up steps are included
- The processing plant fossil fuel requirements and its associated emissions are mainly for moving the biomass around the plant within the plant gate. All options used comparable diesel fuel on a biomass weight basis
- The CO emissions shown are generated primarily from fossil fuels required (mostly diesel fuel) for internal plant requirements

Conclusions

- Biomass derived products will likely offer comparable carbon monoxide emissions compared to petrochemicals
- There is a strong caveat in that subsequent portions of the value chain have not been considered in this analysis; this approximates the emissions generated up to the primary processing plant gate
- Diesel engine use both in biomass production/harvesting and primary processing contribute significantly to the generation of CO emissions.

Carbon monoxide emissions occur mostly during primary processing with the combustion of waste gases and waste process fuels.



Biomass products have similar issues as biofuels with respect to solid and effluent waste. The major issue is likely to be water treatment capacity.

Solid Waste

- Solid wastes issues are likely to be manageable for projected single plant sizes
- Solid waste is likely to be less an issue for bioproducts as compared to biopower applications and the same as for biofuels
- Solid waste production and disposal may be an issue for fermentation based processes which generate waste biomass in the form of organic cell mass materials
- Ash production is may still be an issue since most biomass product plants (in the form of bio-refineries) will use lignin and cell mass as fuel for on-site power generation
  - Biomass ash is generally non-toxic and is capable of being used, and even sold, for beneficial purposes (e.g., fertilizer)

Effluent Waste

- Effluent can originate from a number of sources, but is usually preventable
  - Effluent from fermentors is typically filtered and recycled, and the solids are de-watered for handling as solid wastes
  - Facilities may have to monitor or control storm and wash-down runoff, which may contain substances leached from biomass storage and handling areas
  - Effluent can contain suspended solids and BOD[1], but toxicity is not usually a serious concern
- Fischer-Tropsch based processes generate water which may be treated and used for irrigation of the biomass feedstock
- Water requirements for mega-scale fermentation-based plants may be an issue in semi/arid geographical areas and might limit choice of plant location

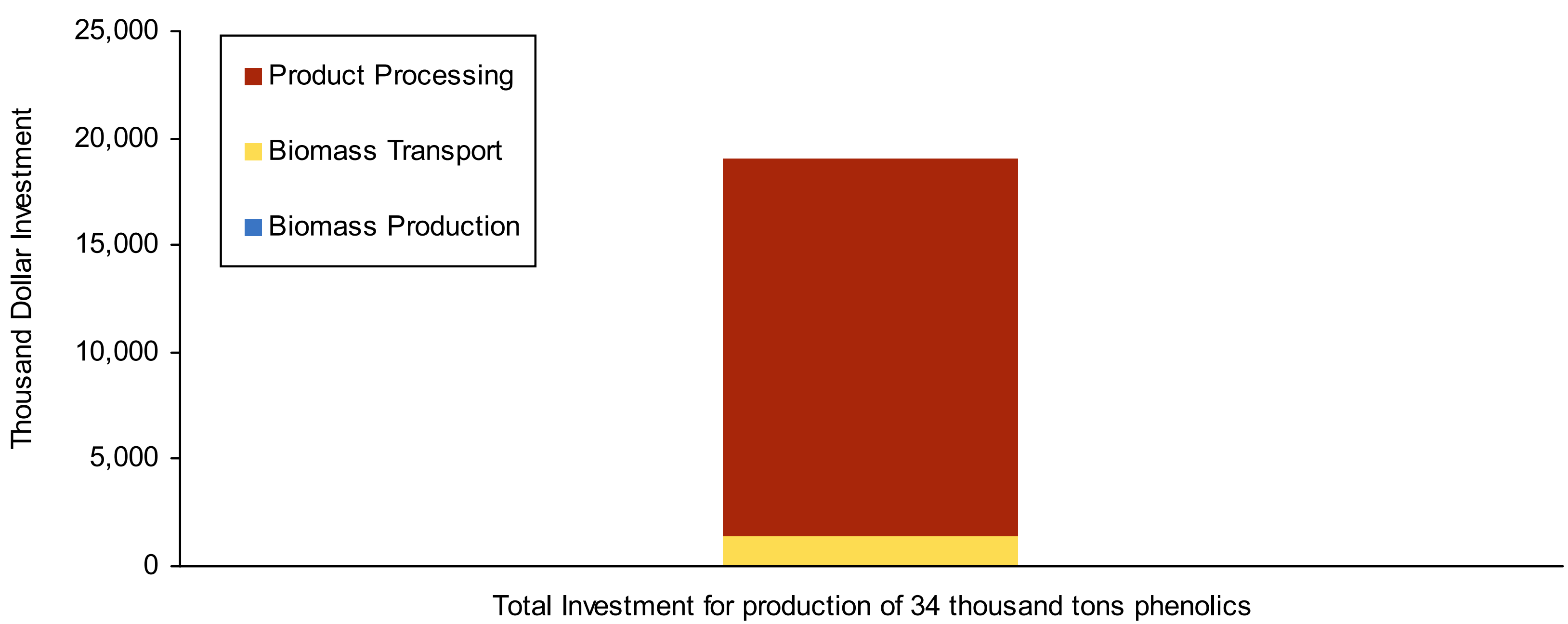
[1] Biological Oxygen Demand, which is a measure of the potential of organic wastes to compete with aquatic life for dissolved oxygen

The method of analysis has implications in the conclusions for possible economic impact of accelerated biomass use for bioproducts.

- We assumed that the capital investment associated with biomass production is contained in the feedstock price
- One weakness of this method is that it does not account for any additional investment of equipment that is needed to collect the biomass not currently harvested
- Additional investments may be required such as for water treatment, especially for fermentation-based processes
- The investments shown produce a total of:
  - For phenolics using woody biomass, 139,000 dry tons woody biomass yield 34,000 tons (68 million pounds) phenolics for formaldehyde-phenol resin applications
  - For 1,3-propanediol using corn, 288,000 dry tons corn yield 2,650,000 tons diol (5.3 billion pounds)

Most investment will likely be associated with the processing plant; the investments for biomass production are embedded in the biomass price.

Total Capital Investment for Phenolics from Poplar/wood to Plant Gate
Thousand dollars for 139,000 dry tons Poplar to 34,000 tons phenolics

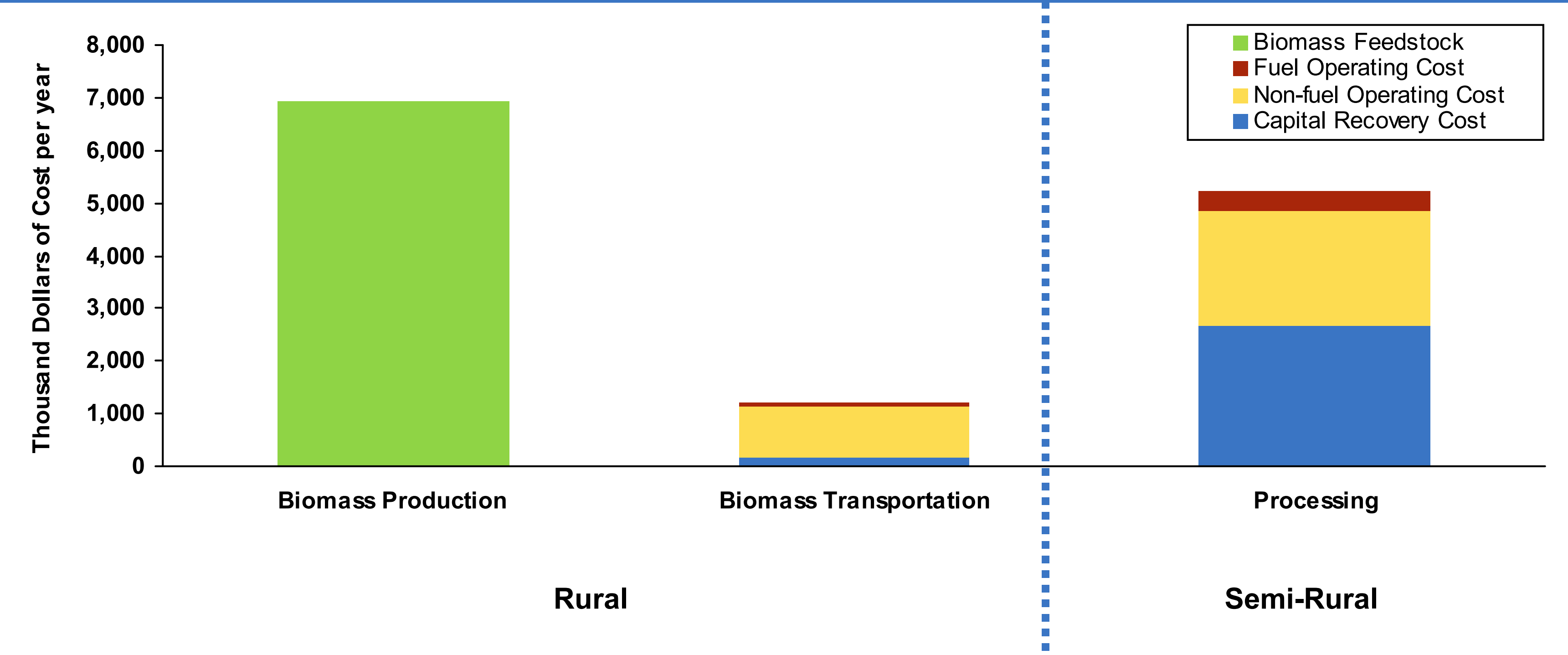


1. The capital investment associated with biomass production is assume to be contained in the feedstock cost.

Additional investments for biomass production are likely in form of land and harvesting equipment.

The annual costs for phenolics is weighed towards biomass feedstock followed by costs associated with processing.

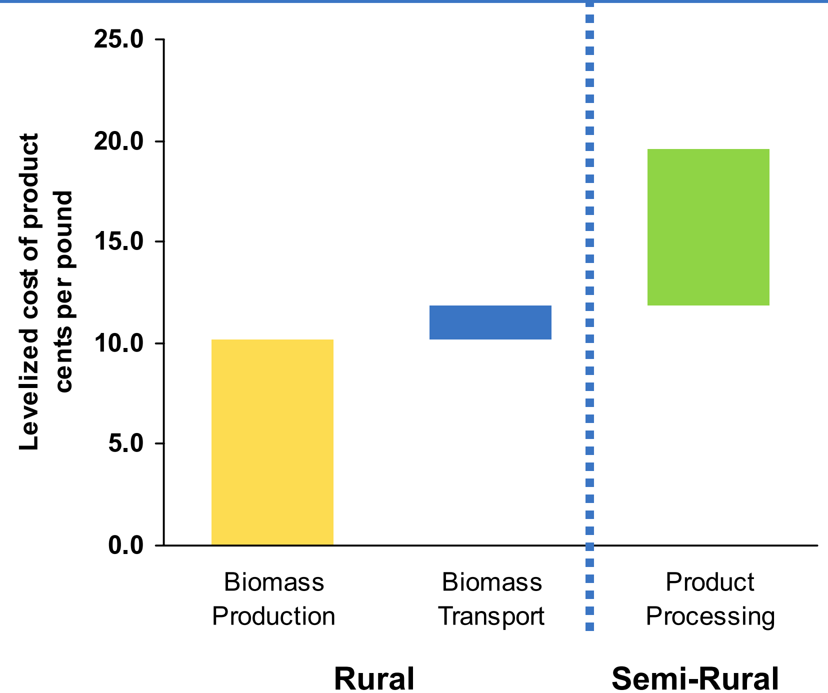
Phenolics from poplar/wood, Levelized Cost of Product to Plant Gate
Cost of Product, $thousand/yr for 34,000 tons Phenolics



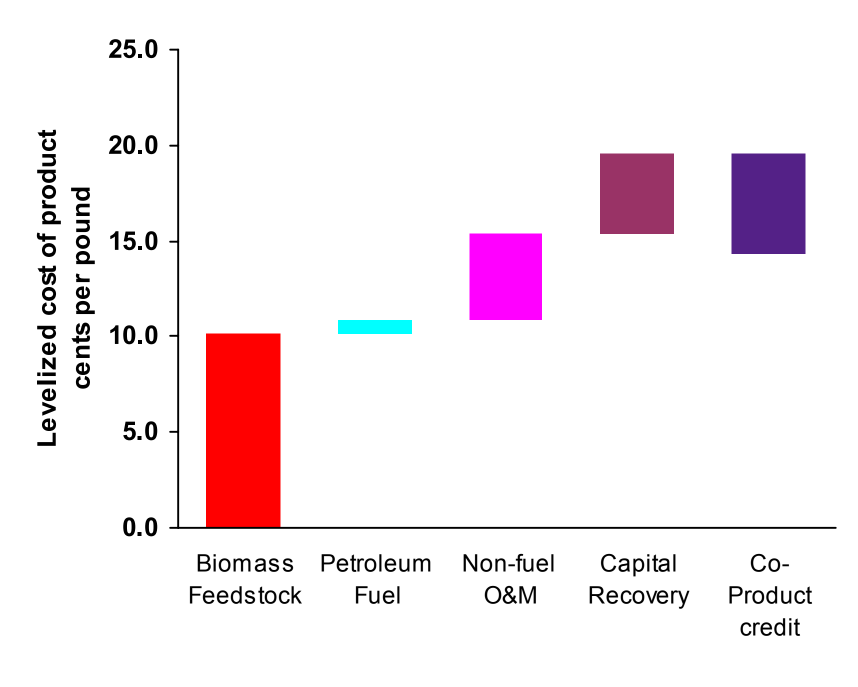
1. Capital recovery cost per year are a 13% per year for biomass transport investment and 15% for product processing investment
2. The fuel operating cost for biomass production is solely the cost of the biomass. The capital, non-fuel operating, and petroleum fuel costs in biomass production are incorporated into the price for biomass
3. The feedstock cost of poplar is $50 per ton.
4. Production volume shown is 34 thousand tons phenolics using 139,000 dry tons woody biomass.

The value creation for phenolics, as an example, is spread across rural and semi-rural areas.

Phenolics from poplar/wood Levelized Plant Gate Cost of Product, cents per pound

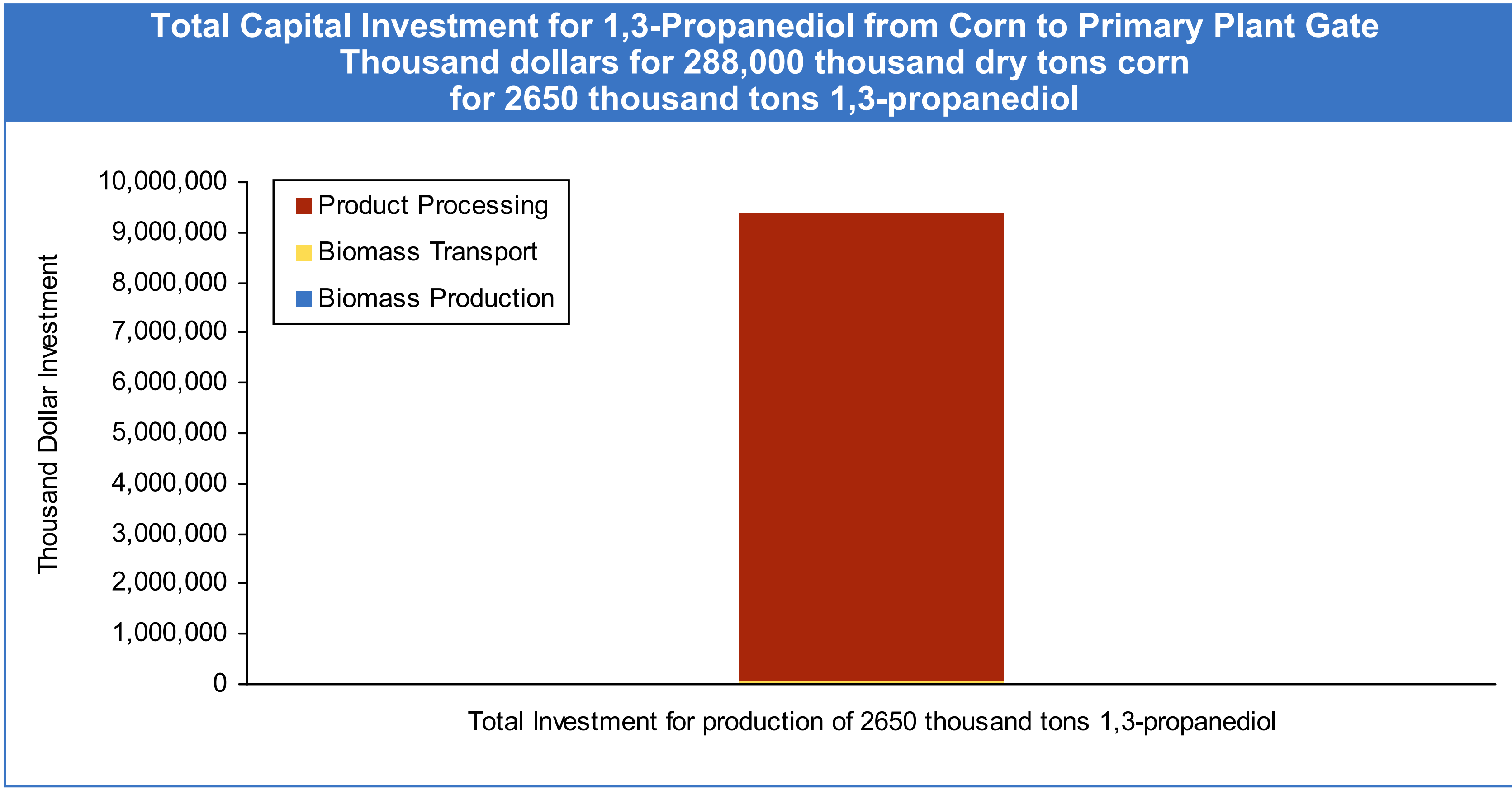


Phenolics from poplar/wood Levelized Plant Gate Cost of Product, cents per pound



1. Capital recovery cost per year are a 13% per year for biomass transport investment and 15% for product processing investment. The capital recovery for biomass production is included in the price for biomass.
2. The capital, non-fuel operating, and petroleum fuel costs in biomass production are incorporated into the price for biomass
3. The feedstock cost of poplar is $50 per ton.

Most investment will likely be associated with the processing plant; the investments for biomass production are embedded in the biomass price.

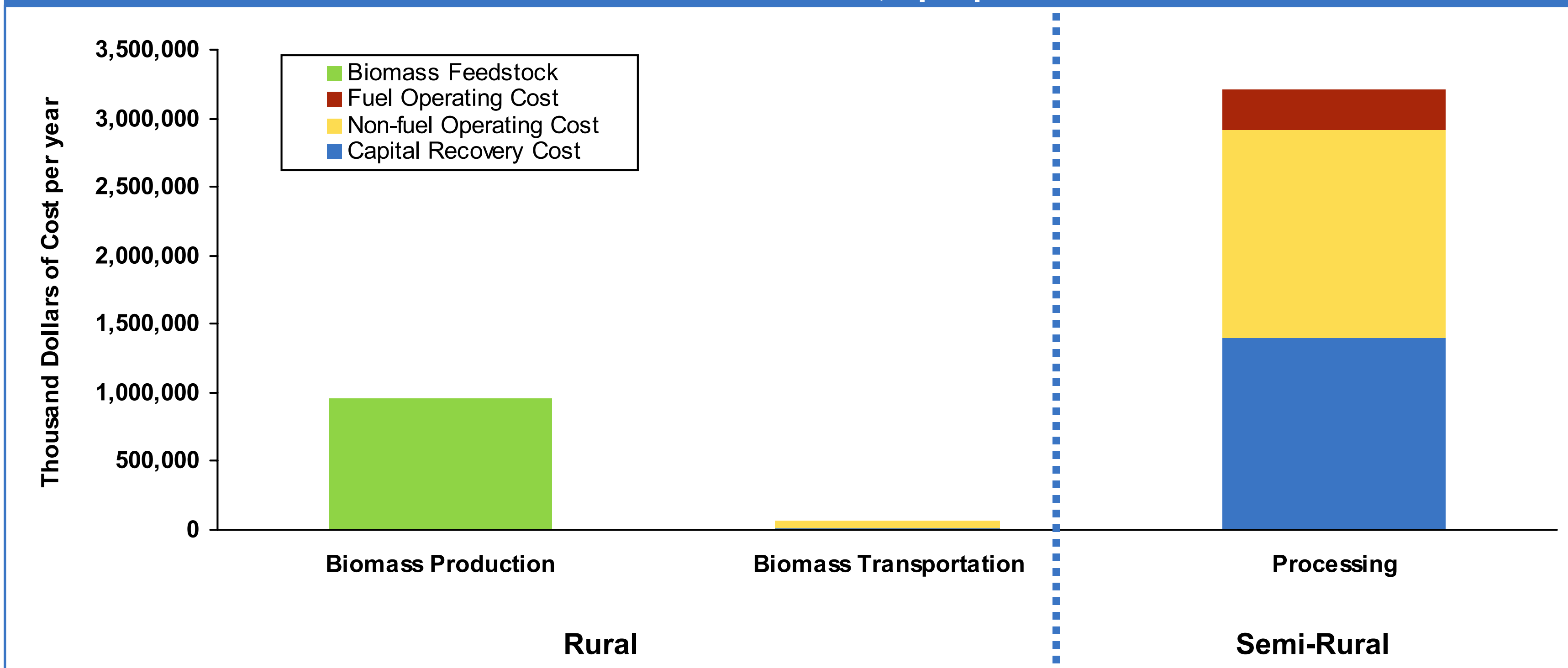


1. The capital investment associated with biomass production is assume to be contained in the feedstock cost.

Additional investments for biomass production are likely in form of land and harvesting equipment.

Annual costs for fermentation products such as 1,3-propanediol will be associated with processing, provided inexpensive feedstocks are available.

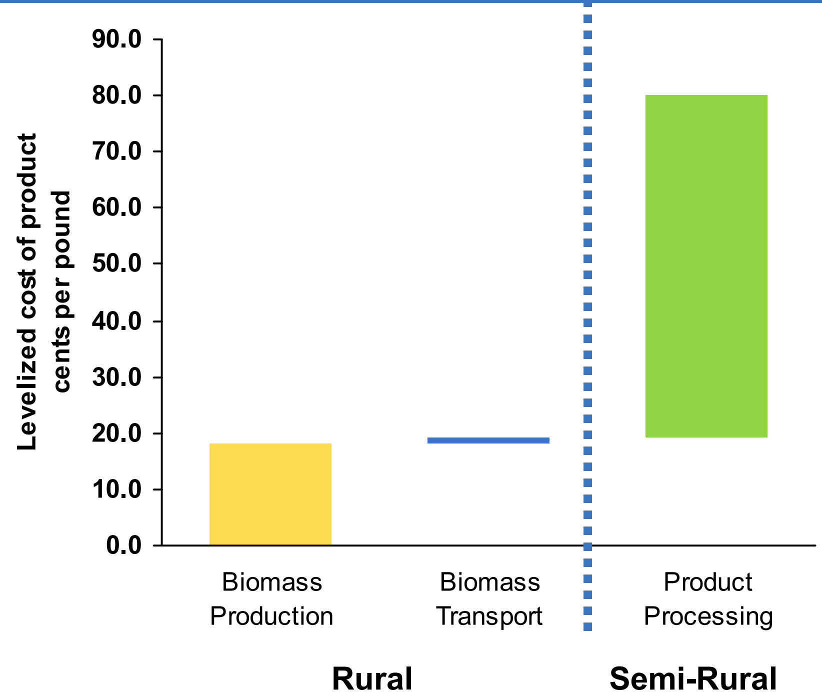
1,3-Propanediol from corn, Levelized Cost of Primary Plant Gate, Cost of Product, $thousand/yr for 288,000 thousand dry tons corn for 2650 thousand tons 1,3-propanediol



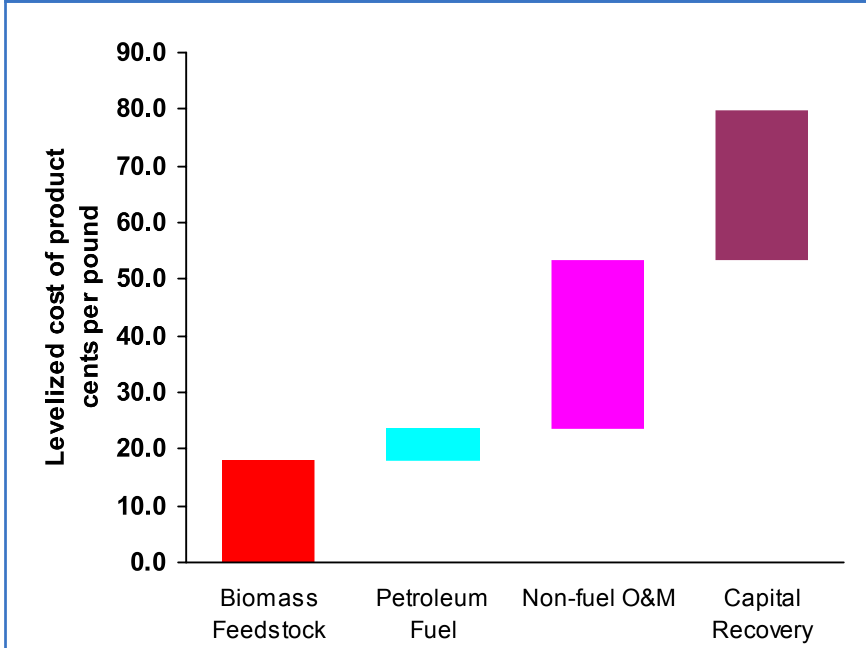
1. Capital recovery cost per year are a 13% per year for biomass transport investment and 15% for product processing investment
2. The fuel operating cost for biomass production is solely the cost of the biomass. The capital, non-fuel operating, and petroleum fuel costs in biomass production are incorporated into the price for biomass

Using 1,3-propanediol as an example, the bulk of value creation will be in semi-rural areas where the processing plants will be built.

1,3 Propanediol from corn Levelized Cost of Product Plant Gate, cents per pound



1,3 Propanediol from corn Levelized Cost of Product Plant Gate, cents per pound



1. Capital recovery cost per year are a 13% per year for biomass transport investment and 15% for product processing investment. The capital recovery for biomass production is included in the price for biomass.
2. The capital, non-fuel operating, and petroleum fuel costs in biomass production are incorporated into the price for biomass

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Scenario analysis was used to understand the impact of time-related factors in achieving the potential impacts of the biomass options.

- The screening and benefit & impact analysis primarily focused on the ultimate potential of each of the options
  - Assuming matured technology
  - Assuming complete market penetration
- Implementing these options will take time, and will require the right actions to be taken in a timely manner, due to various factors, including:
  - Time required for technology development process
  - Time required for application and market development
  - Market barriers
  - Implementation of necessary policy actions
- To gain a better understanding of the actions that will be required to achieve a significant impact with the biomass options, a scenario analysis was performed

For each category of options, a business as usual (BAU) and an aggressive scenario were developed.

- Business as usual (BAU) scenarios project forward what the impacts would be if no special actions were taken:
  - Assumes successful technology development and rates of progress consistent with best in class performance
  - Assumes that policy instruments currently in place will continue to be in place in the future
  - Is based on EIA baseline forecasts for energy prices, economic growth etc.
- The aggressive scenario starts with a biomass vision and asks what actions would have to be taken to achieve as much impact as possible:
  - Visions for each of the biomass option categories were developed in a workshop with industry experts
  - Detailed timelines were developed to support achieving these visions
  - Action items were identified that would need to be taken in order to meet the timelines
  - Aggressive assumptions were used with respect to:
    - Technology and application development progress rates
    - Technology performance
    - Market acceptance of and market pull for products
    - Market penetration rates achievable
- Basic economic factors, such as economic growth and energy prices, are the same in both scenarios
- Technologies are assumed to mainly capture growth markets, rather than replacement (exceptions are black liquor gasification, biomass co-firing, and oxygenate fuel blend stocks)

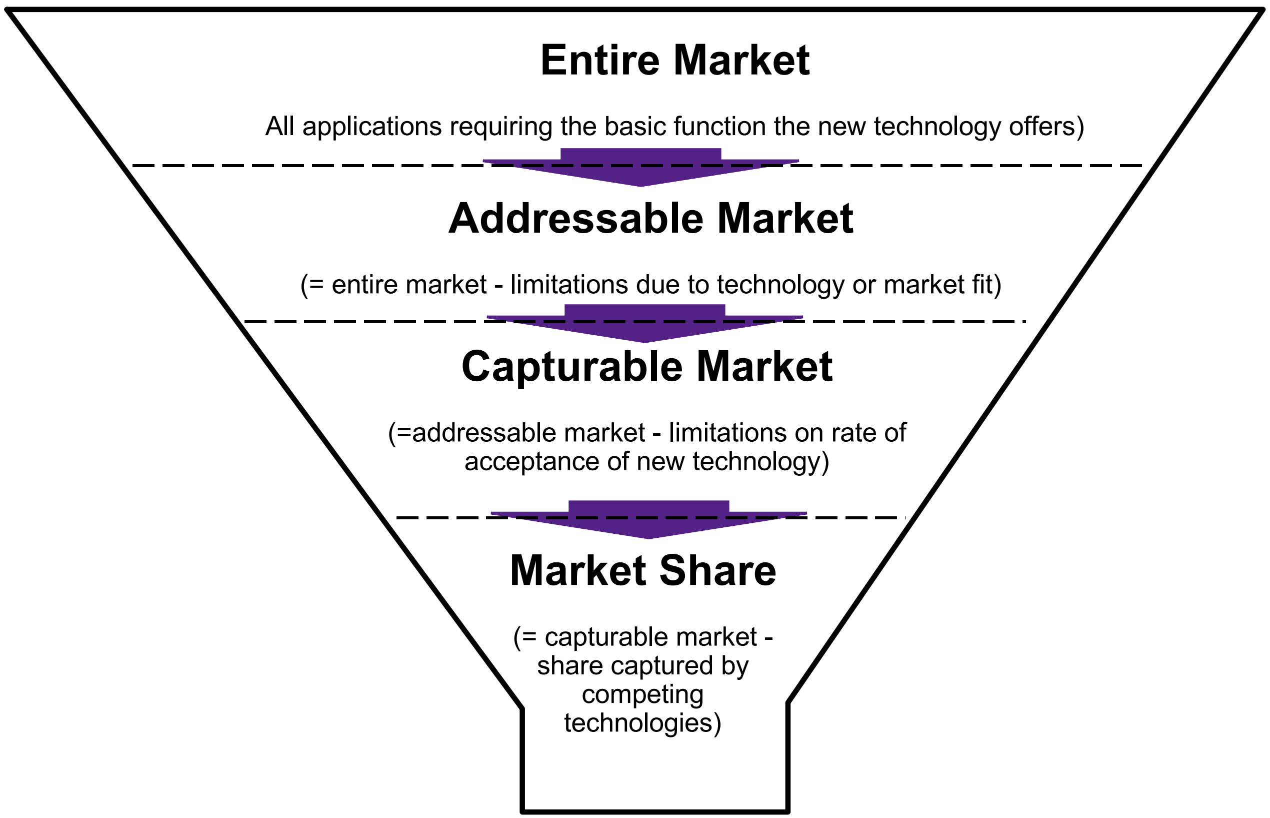
For each sector a baseline was defined and projected out to 2010.

Sector	Conventional Units	BAU 2010 Baseline	Aggressive 2010 Baseline	Comments
Biopower	MW	10,000	10,000	No growth in baseline
Biofuels	million gallons ethanol	1500	1600	• In BAU, biofuels baseline grows at 1.4% per year (projected rate of motor gasoline demand • For aggressive implementation, biofuels baseline grows at 1.8% per year (projected rate of total transportation fuels demand)
Bioproducts	Billion pounds	21	21	Both the BAU and aggressive scenarios grow at 1.8% per year (projected rate of total transportation fuels demand)

1. All growth rate projections taken from USDOE EIA 2001 Energy Outlook, reference case.

The scenario analysis involves forecasting the market penetration of emerging technologies.

Performed During Screening



Industry Analysis
(Power generation, transport fuels, commodity chemicals)

Comparison of industry needs with technology characteristics
(feedstock compatibility, fit with current infrastructure)

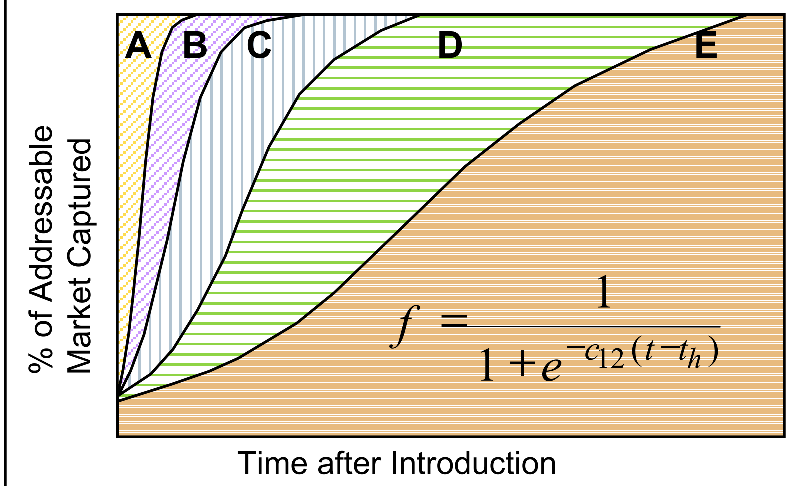
Market acceptance analysis
(this analysis)

Analysis of competing technology *(not considered)*

total market capacity x % market addressable x Market penetration (% captured) x % market share = # installed capacity

To aid projecting the *capturable* market, we categorized the technology / market spectrum based on a few important criteria.

- The rate at which technologies capture the market depends on:
  - Technology characteristics (technology economics, new versus retrofit)
  - Industry characteristics (industry growth, competition)
  - External **drivers** (government regulation, trade restrictions, wars)
- Historical data reveals that major classes of technology/market with common market-penetration characteristics can be distinguished
- The Fisher-Pry technology substitution model **is a relatively simple but useful way to** predict market penetration for an existing market of known size



The half time t_h is the time at which $f = 0.5$

The takeover time t_s is the time between $f = 0.1$ and $f = 0.9$

The parameter $c_{12} = 2 \ln(9)/t_s$

Five technology classes, based on historical data for technology introductions, were used to characterize market penetration rates.

Characteristic	A	B	C	D	E
Time to Saturation (t_s)	5 yrs	10 yrs	20 yrs	40 yrs	>40 yrs
Technology Factors					
Payback discretionary	<<1 yrs	<1 yrs	1-3 yrs	3 - 5 yrs	>5 yrs
Payback non-discretionary	<<1 yrs	<1 yrs	1 - 2 yrs	2 - 3 yrs	>3 yrs
Equipment life	<5 yrs	5 - 15 yrs	15 - 25 yrs	25 - 40 yrs	> 40 yrs
Equipment replacement	None	minor	Unit operation	Plant section	Entire plant
Impact on product quality	++	++	++	+	O / -
Impact on plant productivity	++	++	++	+	O / -
Technology experience	New to U.S. only	New to U.S. only	New to industry	New	New
Industry Factors					
Growth (% p.a.)	> 5%	> 5%	2 - 5%	1 - 2%	<1%
Attitude to risk	open	open	cautious	conservative	averse
External Factors					
Government regulation	forcing	forcing	driving	none	none

By rating all applicable categories, consensus can be reached on the appropriate classification and the likely market penetration rate.

For the technology development timelines we used our stages-of development analysis and associated best-in-class timelines.

Technology *(basic materials, working principles)*

First Evidence	Technology Viability	Technology Verification	Advanced Development	Commercialization
8-15 years	5-10 years	3-8 years	1-4 years	0-2 years

Production Process *(process to manufacture technology)*

First Evidence	Proof of Principles	Unit Operation Development	Process Integration & Demonstration	Commercialization
8-15 years	5-10 years	3-8 years	1-4 years	0-2 years

Product *(Product incorporating technology)*

First Evidence	Product Concept Viability	Product Design	Advanced Development	Commercialization
2-15 years	2-15 years	1-4 years	0-1 years	0-0.5 years

Market *(Customers that want to buy products)*

Customer Need	Product Idea Development	Product Concept Development	Product Refinement	Initial Product Launch
2-6 months	1-6 months	1-6 months	2- 12 months	2-8 months

Some of the processes based on biological processes can take somewhat longer to mature. Polymer market development can take much longer time scales.

The progression of bioproduct use is dependent upon technology introduction timing, target market size and rate of product penetration.

- The timing of technology introduction is dependent upon the stage of development of the technology
  - There exist key development events that are required for commercialization
  - Typical times are required at each stage in order to decrease technical risk
- There is a limit to the rate at which green-field plants are built and brought on-line
  - Especially for new process technologies, EPC contractors with the necessary experience may be limited
  - New technology green-field plants may require longer start-up times to full capacity
  - Experience will be collected with the new plant before construction of the second and third plants are likely to be undertaken
- The target market is based primarily on the actual and perceived performance characteristics of the product and its cost structure
- The rate of market penetration will be dictated by the cost structure of the product, its potential benefits, and industry and government factors

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Both the current reality and an extrapolated future are factored into the *Business-as-Usual* and *Aggressive Growth* scenarios for biomass power.

- The focus of the quantitative scenarios was on the technologies that passed through the screening process reviewed in Section 3 of this report
  - Technologies like grid-sited biomass-only IGCC, while part of the vision for biomass power, were not part of the quantitative scenario because it did not pass the screening process based on constraints imposed by looking out to 2010
- The BAU scenario assumes that the industry does grow gradually, but that the focus is on “low-hanging fruit”
  - Options requiring significant technology development or that face other hurdles are not deployed in the BAU scenario
- The aggressive growth scenario is consistent with a robust 2020 vision for the biomass energy industry that was developed by Arthur D. Little
  - Technology advances are rapid and significant
  - There is strong support from the public sector to level the playing field for biomass (via direct support and via state restructuring plans that include provisions for renewable energy)
  - Market conditions favor fuel diversity and green power
- In both scenarios, the baseline of biopower is 10,000 MW capacity and has zero growth in the baseline out to 2020

Since these are scenarios, they do not include the full suite of biopower technologies, but use a variety of options to illustrate what is possible.

Biomass co-firing and landfill gas figure prominently in the BAU scenario, while gasification options are only deployed if biopower is pursued aggressively.

Technologies*		Business-as-Usual	Aggressive Growth
“Low Hanging Fruit”	• Direct co-firing of biomass with coal • Landfill gas • Other biogas (from sewage treatment, animal waste and other sources)	• Gradual deployment of available technologies • Fuel cells make gradual inroads in landfill gas • Co-firing focused on “best” feedstocks	• Rapid deployment of available technologies • Fuel cells penetrate more rapidly • Multiple feedstocks used in co-firing
Gasification of Process Residues	• Pulp & paper – Black Liquor IGCC plants – Hogged fuel, bark, sludge IGCC plants • Other process residues – Lumber, food processing, etc.	• Introduction and deployment of gasification for use with onsite residues is expected to be slow – Limited to best applications – Fewer products available • Pulp & paper industry very slow to adopt gasification for commercial use	• Successful deployment of gasification for use with onsite residues at a variety of scales – Widely deployed where residues are available – Many products available • Pulp & paper industry successfully adopts gasification technology
Other	• Co-firing of gasified biomass in coal Rankine and natural gas GTCC power plants • Refuse derived fuel IGCC plants	• Gasification for co-firing not expected to be deployed at all due to perceived risks and higher capital costs relative to direct firing • RDF never accepted by public as viable option - no new capacity built	• Gasification widely accepted as viable technology - leads to gradual deployment starting in 2004 • RDF accepted by public as viable option - new capacity gradually deployed starting in 2009

* For the purposes of the scenarios, not all technology/fuel combinations have been included. The scenarios are meant to be illustrative.

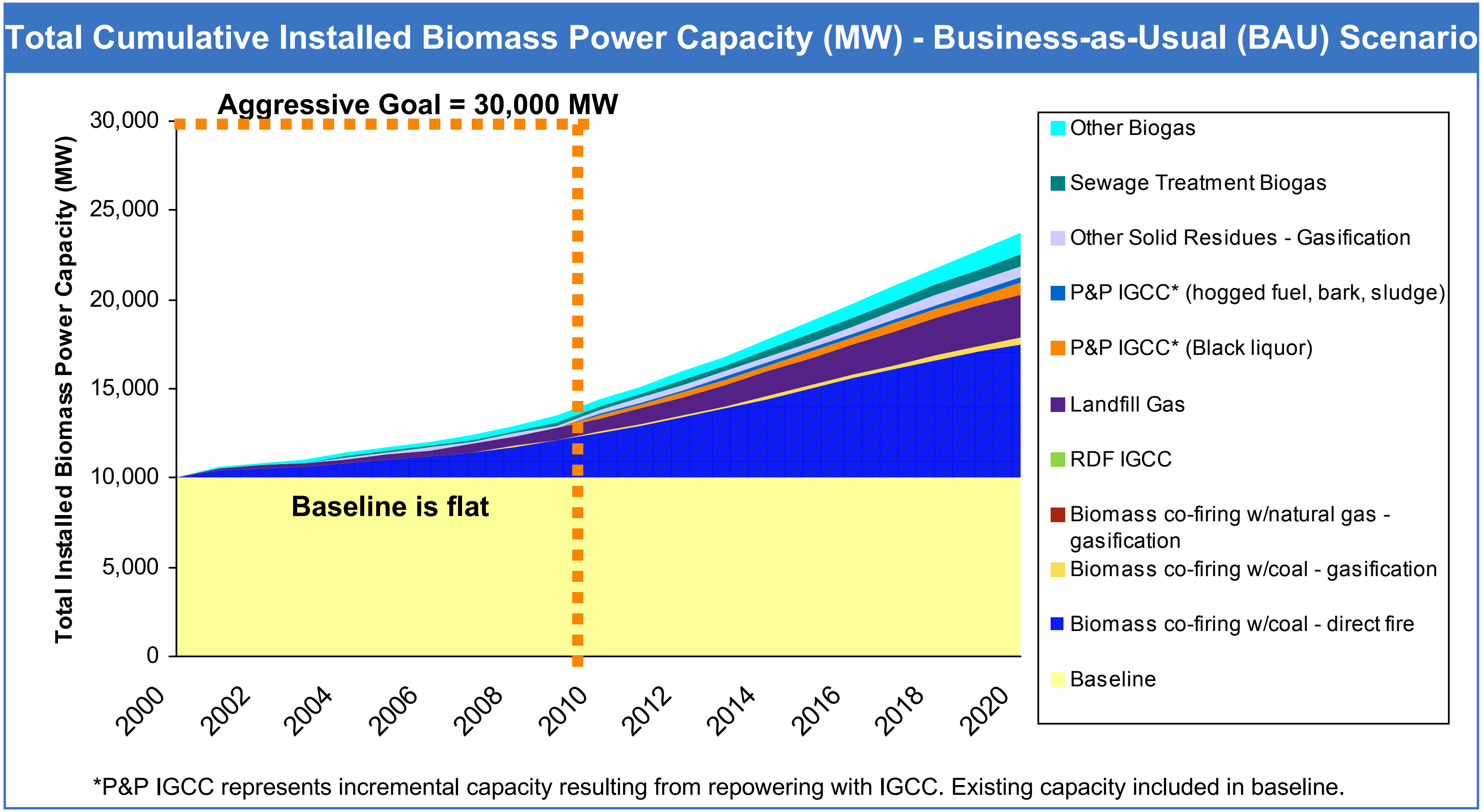
In the BAU scenario, biopower technologies are expected to "saturate" the market in 20-40 years.

Business-as-Usual Scenario Assumptions

	Co-Firing				Landfill Gas		
	Direct firing with coal Rankine	Gasification with coal Rankine	Gasification with NG GTCC	RDF IGCC	internal combustion Engine	Gas Turbine	Fuel Cell
Percent of addressable market that is capturable	30%	0%	0%	0%	33%	50%	17%
Market growth rate (% per year)	0%	N/A	N/A	N/A	1%	1%	1%
Year of introduction	2001	N/A	N/A	N/A	2001	2001	2004
Time for market saturation (years)	20	N/A	N/A	N/A	20	20	40

	Pulp & Paper IGCC		Other Solid Residues - Gasification		Sewage Treatment Biogas		Other Biogas (e.g. digester gas)	
	Black Liquor	Hogged Fuel, Bark, Sludge	internal combustion Engine	Gas Turbine	Gas Turbine	Fuel Cell	internal combustion Engine	Gas Turbine
Percent of addressable market that is capturable	70%	100%	50%	50%	50%	50%	50%	50%
Market growth rate (% per year)	0%	0%	2%	2%	2%	2%	2%	2%
Year of introduction	2010	2010	2004	2004	2001	2004	2001	2002
Time for market saturation (years)	40	40	40	40	20	40	40	40

In the BAU scenario, biomass power achieves approximately 40% growth in capacity (over baseline) by 2010 and could more than double by 2020.



*P&P IGCC represents incremental capacity resulting from repowering with IGCC. Existing capacity included in baseline.

Growth is limited by both the rate of technology deployment and because several applications are not expected to be deployed at all.

Biomass power use could double by 2010 but requires that several factors combine favorably in addition to strong government support.

- Biomass co-firing with coal is critical for rapid, near-term growth and is responsible for over 50% of the growth
  - Direct co-firing using non-woody fuels will likely be required, which will itself require further technology development and demonstration
  - May be potential for synergy with new clean-coal-based technologies (not included in analysis)
- Biomass integrated gasification combined cycle (BIGCC) technology in the pulp & paper industry is the second most important contributor with almost 20% of the growth through 2010, and with greater potential post-2010, provided the technology is successfully adopted by the industry
- Landfill gas and other biogases also figure prominently in the aggressive growth scenario for early growth
  - Technologies are available today
  - USDOE should focus on removing economic or regulatory barriers
- Other gasification options are less important in the near-term but are important for sustained growth:
  - Other industries that generate residues are expected to contribute modestly throughout the 2000-2020 timeframe
  - RDF could become a significant source of biopower in the long term, provided technical and environmental issues are addressed successfully
  - Gasification for co-firing could become significant beyond 2010, in both coal- and natural gas-fired power plants
- Implementation of the Aggressive Growth scenario would require several successful simultaneous developments:
  - Biomass supply infrastructure to develop rapidly if the market potential is to be realized
  - Successful development of gasification technology
  - Successful elimination of regulatory barriers to biopower implementation
- It would also require significant government support to overcome the cost difference of some longer-term options and expected market prices

The quantitative aspects of an *Aggressive Growth* scenario were based on a robust 2020 vision for the biomass industry.

The vision:

- Was developed by Arthur D. Little to guide the development of a scenario in which it would be possible to triple the production of biomass power
- Went out to 2020 so as not to constrain technology options only to those that would be commercially viable before 2010
- Considered technology, market and regulatory issues
- The vision begins with a desired end-state in 2020 and then “writes the history” required to achieve the desired end-state
- The baseline is 10,000 MW capacity with zero growth out to 2020

In the desired "end-state", multiple biopower technologies are commercially available with some markets fully exploited.

2020 End State

Co-Firing

Biomass co-firing with coal fully exploited at a variety of scales and firing percentages

10-15,000 MW co-firing in operation

Biomass infrastructure developed to deliver large quantities of biomass (energy crops, residues)

- Large companies involved
- Market mechanisms in place similar to other fuels (e.g., futures, B2B)

Grid Power

Gasification-based technology is scale independent and low cost

RDF gasification fully accepted as viable option - commercially viable

Landfill gas fully exploited - 3,000 MW added

Common technologies between utility-scale IGCC are transferred to P&P industry for hogged fuel and bark residues

Common technologies between landfill gas, digester gas and other applications are transferred across market segments. Technology developments are applicable to biomass fuels and products applications

- Small-scale power generation
- Gas cleanup
- Low-medium Btu combustion systems
- Project development learning and business models (e.g., for many small-scale sites)
- Partnerships

Onsite Power & CHP

Conversion technology is scale independent and low cost

Residues used for highest value application

5-6000 MW added in P&P through efficiency gains from gasification (black liquor, hogged fuel, bark, sludge). (Capacity added via increased biomass utilization for power only, which is part of the 2020 Vision of the pulp & paper industry, would be in addition to this amount).

Legend:
- Biomass Co-firing with coal
- Gasification/IGCC
- Biogases
- Power in P&P
- Regulations & Biomass markets
- Small-scale Gasification

1. We selected 2020 as the year to focus the vision to avoid missing attractive technologies that only barely achieve market introduction by 2010.

The aggressive growth scenario will require early technology demonstration combined with significant market and regulatory support.

Legend:
- Biomass Co-firing with coal
- Gasification/ IGCC
- Biogases
- Power in P&P
- Regulations & Biomass markets
- Small-scale Gasification

2002 | 2003 | 2004 | 2005

Co-Firing

- Specs for fly ash accepted - biomass content is OK
- NO_x Trading begins
- Special co-firing incentive to encourage early adoption - targeted to first 15-20 commercial plants
- U.S. demo of gasification co-firing in a coal plant
- Co-firing broadly accepted as green power - certification is given
- Solid co-firing with herbaceous biomass is as "easy" as with woody biomass
- Biomass fuel infrastructure responds to growing demand - large companies enter
- 1st commercial gasification co-firing in a coal plant
- 3000-5000 MW in operation
- Demonstration of gasification co-firing in GTCC

Grid Power

- U.S. demo of utility-scale biomass IGCC
- Aggressive development of landfill gas projects begins
- Lack of landfill space renews interest in RDF conversion
- Standardization for landfill gas projects streamlines development & reduces cost & shortens lead time
- EPA strengthens commitment to methane mitigation
- Microturbines deployed routinely for smaller landfill gas projects
- Biomass-based green power is available/offered from new biomass capacity
- Advanced gas cleanup for turbines is proven
- 1st U.S. commercial utility-scale biomass IGCC
- Demonstration of gasification of RDF to prove environmental acceptability
- Market optimization occurs for use of biomass residues:
  - buying & selling ("residues.com")
  - onsite utilization (power vs. bedding, vs. mulch, etc.)

Continued electric and gas price volatility and regional supply/demand imbalances provides additional impetus for distributed power, CHP, and fuel diversity.

Onsite Power & CHP

- Next generation small-scale gasification systems
- Concern over impact of animal waste from CAFO on environment grows
- Deployment of digester gas conversion technologies accelerates
- Demo of IGCC using hogged fuel, bark & sludge
- Microturbines deployed routinely for biogas projects
- Chemical recovery hurdles overcome
- Advanced gas cleanup for turbines is proven
- Multiple small-scale gasification systems commercially available:
  - multiple fuels
  - multiple technologies
  - scaleable
- Black liquor gasification demo in full operation

To achieve the aggressive goal before 2020, continued improvement of technology competitiveness will be required.

- Biomass Co-firing with coal
- Gasification/ IGCC
- Biogases
- Power in P&P
- Regulations & Biomass markets
- Small-scale Gasification

	2007	2010	2015	2020
Co-Firing	First commercial gasification co-firing in GTCC	6,000-9,000 MW in operation	10-15,000 MW co-firing in operation Best coal plant sites exploited - growth slows	Some conventional coal plants retiring - Co-firing may be decreasing Shift to co-firing with gasification in GTCC is accelerating
Grid Power	First commercial RDF gasification IGCC	Fuel cells running on landfill gas are competitive relative to other biogas technologies Biomass IGCC deployment at multiple scales accelerates	RDF IGCC deployment accelerates (new and retrofit) $1000/kW or less for IGCC with > 40% efficiency Landfill gas fully exploited - 3,000 MW added	
Onsite Power & CHP	Commercial application of IGCC using hogged fuel, bark & sludge	Demonstrate that IGCC can generally replace Kraft boiler "on the fly" - minimal mill disruption during retrofit Fuel cells running on digester gas are competitive relative to other biogas technologies	Acceptance in mills to replace recovery boiler with gasification - deployment accelerates Digester biogas fully exploited - 3-5,000 MW added Gasification of onsite residues 1-2,000 MW added	

In the *Aggressive Growth* scenario, more attractive performance and cost and market pull allow several technologies to achieve saturation in 10 years.

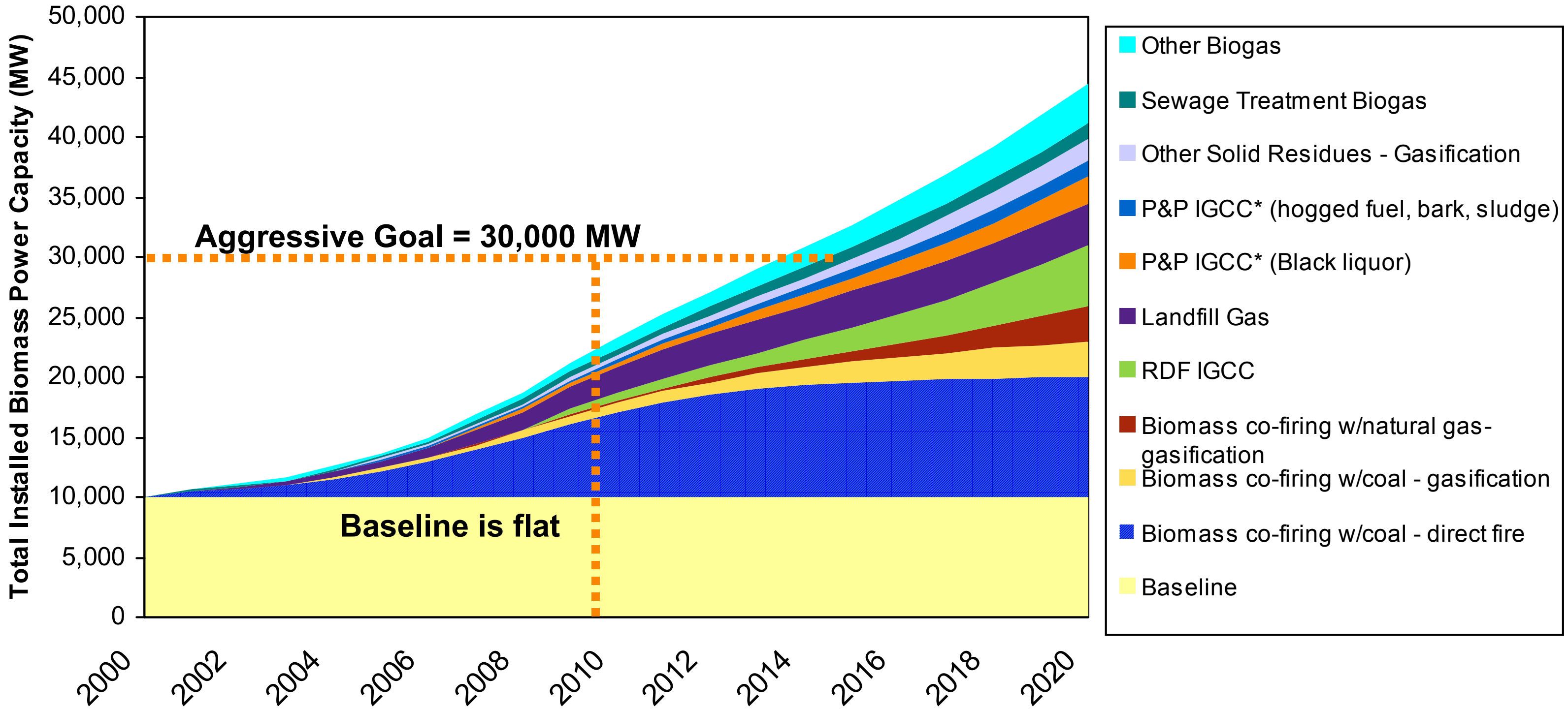
Aggressive Growth Scenario Assumptions

	Co-Firing			RDF IGCC	Landfill Gas		
	Direct firing with coal Rankine	Gasification with coal Rankine	Gasification with NG GTCC		internal combustion Engine	Gas Turbine	Fuel Cell
Percent of addressable market that is capturable	30%	15%	10%	100%	33%	50%	17%
Market growth rate (% per year)	0%	0%	10%	2%	1%	1%	1%
Year of introduction	2001	2004	2007	2009	2001	2001	2002
Time for market saturation (years)	10	20	20	20	10	10	20

	Pulp & Paper IGCC		Other Solid Residues - Gasification		Sewage Treatment biogas		Other biogas (e.g. digester gas)	
	Black Liquor	Hogged Fuel, Bark, Sludge	internal combustion Engine	Gas Turbine	Gas Turbine	Fuel Cell	internal combustion Engine	Gas Turbine
Percent of addressable market that is capturable	70%	100%	50%	50%	50%	50%	50%	50%
Market growth rate (% per year)	0%	0%	2%	2%	2%	2%	2%	2%
Year of introduction	2007	2005	2004	2004	2001	2002	2001	2002
Time for market saturation (years)	20	20	20	20	10	20	20	20

Electricity capacity from biomass could be tripled by 2015 provided that multiple feedstocks and technologies are exploited aggressively.

Total Installed Biomass Power Capacity (MW) - Aggressive Growth Scenario



*P&P IGCC represents incremental capacity resulting from repowering with IGCC. Existing capacity included in baseline.

Provided biomass is available, growth is still possible after 2020 because some applications are still in relatively early stages of market penetration.

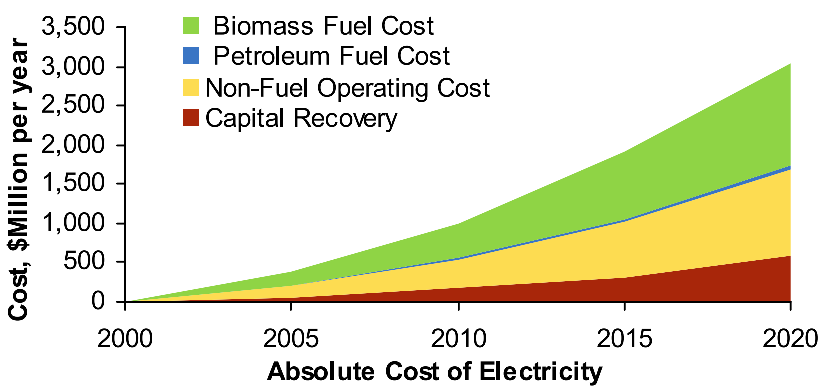
The yearly costs associated with aggressive biopower implementation are mostly related to the biomass feedstock followed by capital recovery costs.

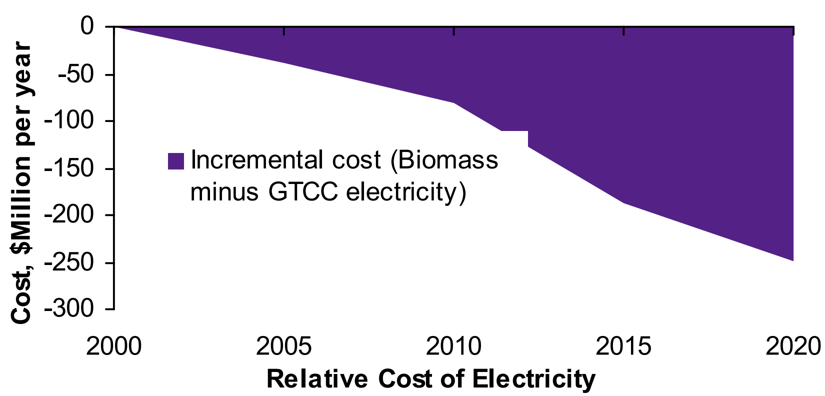
Assumptions and Methodology	• The feedstock cost for cellulosic biomass was $30 per dry ton (farm-gate); ***gaseous biomass and process wastes were considered zero cost feedstock*** • The incremental cost of products was estimated by a comparable electricity demand (GWh) with a value GTCC levelized cost of power of $0.0324 per kWh • Assumed all new capacity (green field plants) were built for the new electricity except for co-firing situations; did not take into account building next to existing petroluem, pulp&paper, or grain processing facilities that would likely reduce investment cost • For co-firing with coal capacity, the emission credits were credited against capital recovery costs
Comments	• Feedstock costs followed by nonfuel operating costs are the dominant cost elements for biopower • Capital recovery is an issue especially as new capacity comes on line (with its higher associated costs)
Conclusions	• In the BAU scenario, the savings in cost of electricity compared to new capacity natural gas GTCC reach $80 MM in 2010 and $250MM in 2020 • In the aggressive scenario, the incremental cost of biomass electricity delivered reaches a savings of $80 million in 2010 and an incremental cost of $1.3 billion in 2020 • Caveats are in the BAU scenario: 2500 MW are in co-firing with coal using existing capacity; ~1850MW are associated with zero cost gaseous biomass and utilization of zero cost process wastes all by 2010 • Caveats are in the Aggressive scenario: 210MW in co-firing with NG GTCC; 7800 MW in co-firing in coal plants; 1015MW for RDG gasification; and 4540MW in utilizing zero cost gaseous biomass and zero cost process wastes; all by 2010

If most process wastes are zero cost and co-firing with coal is implemented, there may be net savings in the COE for biomass implementation: ~$80MM in 2010 for BAU and aggressive scenarios.

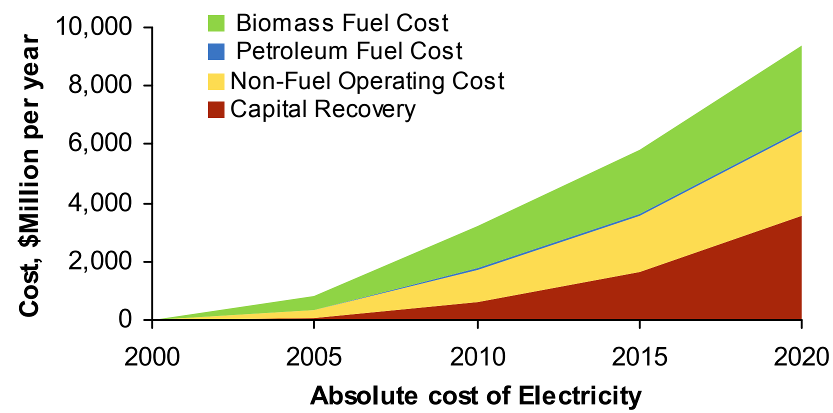
Cost per Year to 2020 (Taxes and credits excluded)
Incremental Million dollars per year

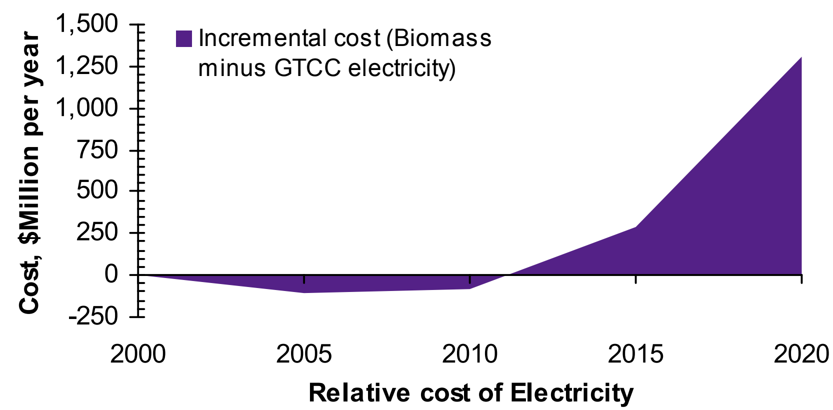
Business as Usual Scenario





Aggressive Scenario

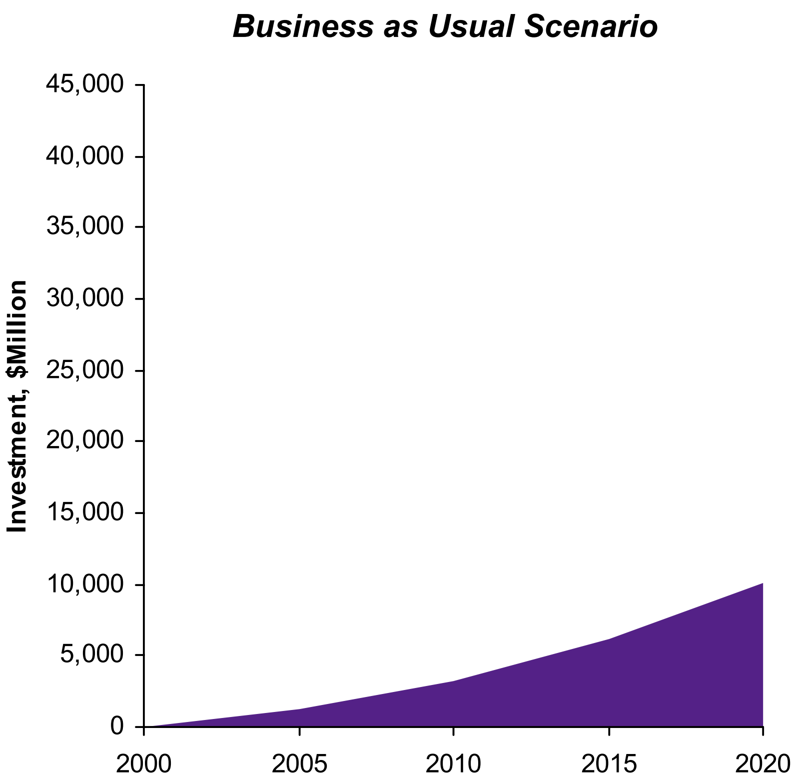


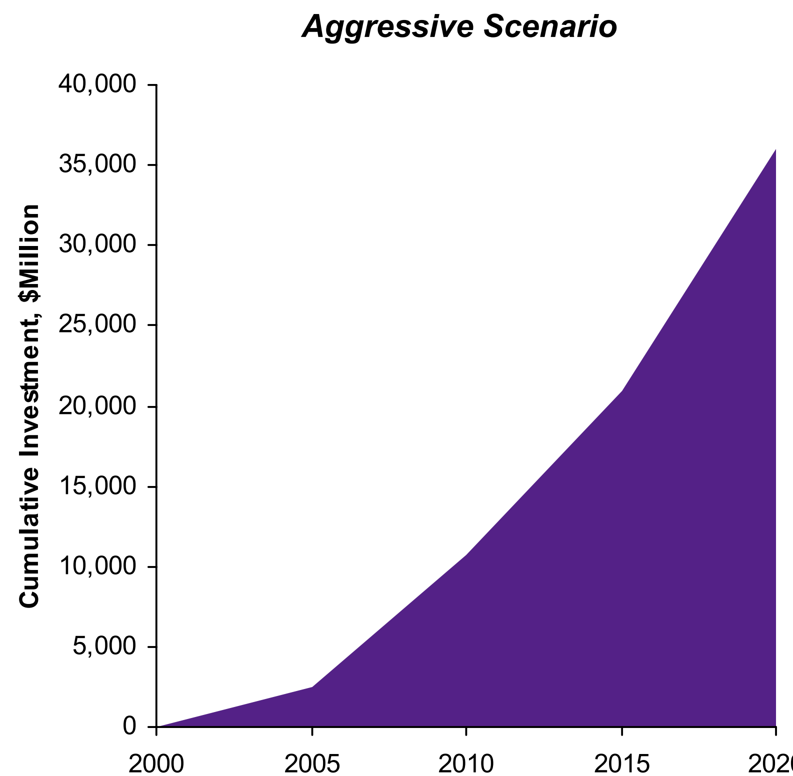


Emission credits were credited against the capital recovery costs for biomass co-firing with coal.

One time investments for aggressive biopower deployment would reach $11 billion by 2010 and $36 billion by 2020 for full implementation.

Investment to 2020
Absolute Cumulative Investment of Incremental Capacity Above Baseline, Million Dollars

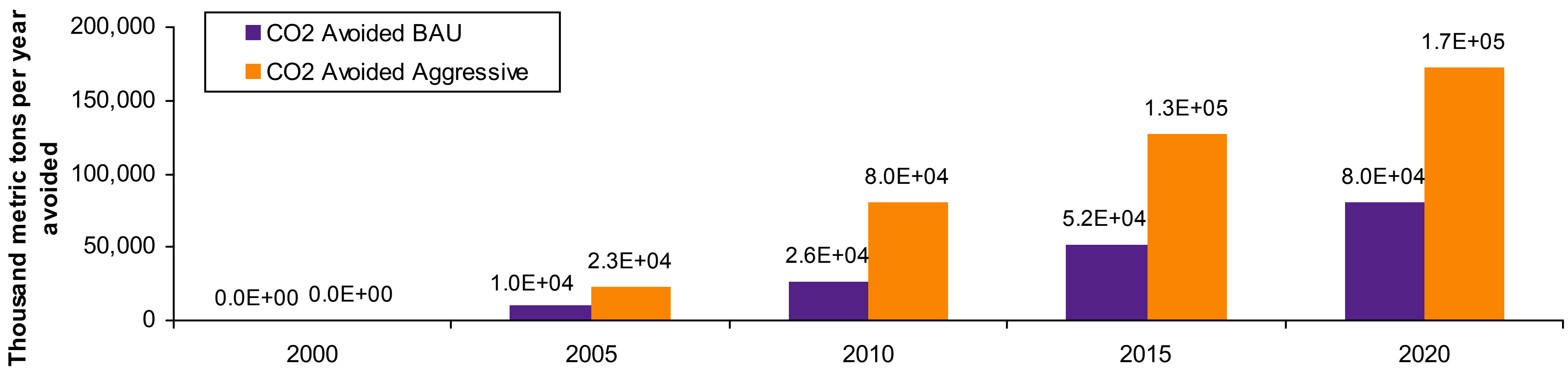


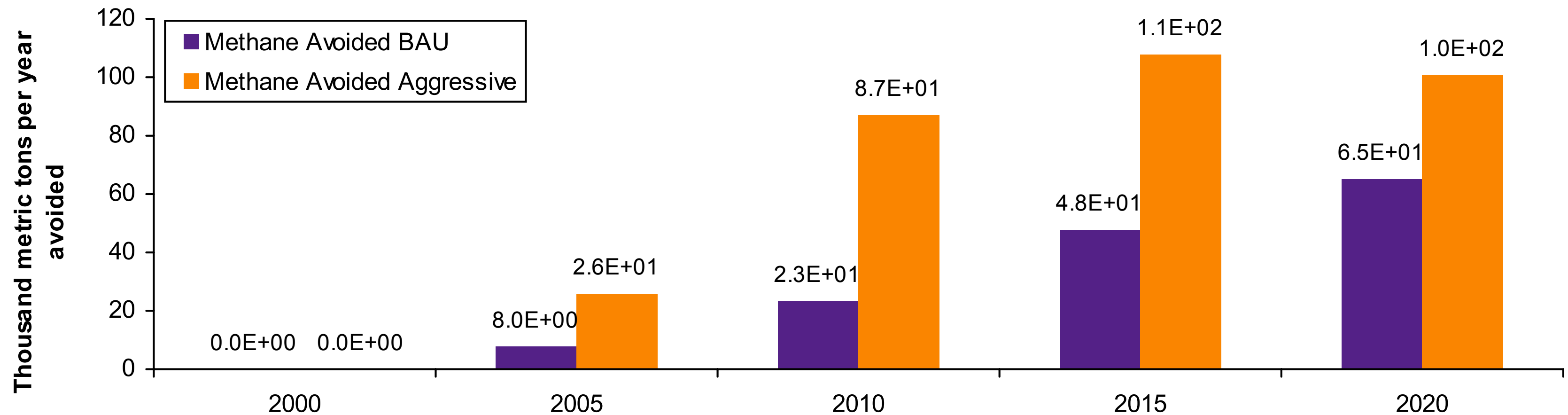


For BAU, the one time investment would reach $3 billion by 2010.

Biopower has significant implications for carbon dioxide reduction. Methane emissions, primarily from coal replacement, may be reduced.

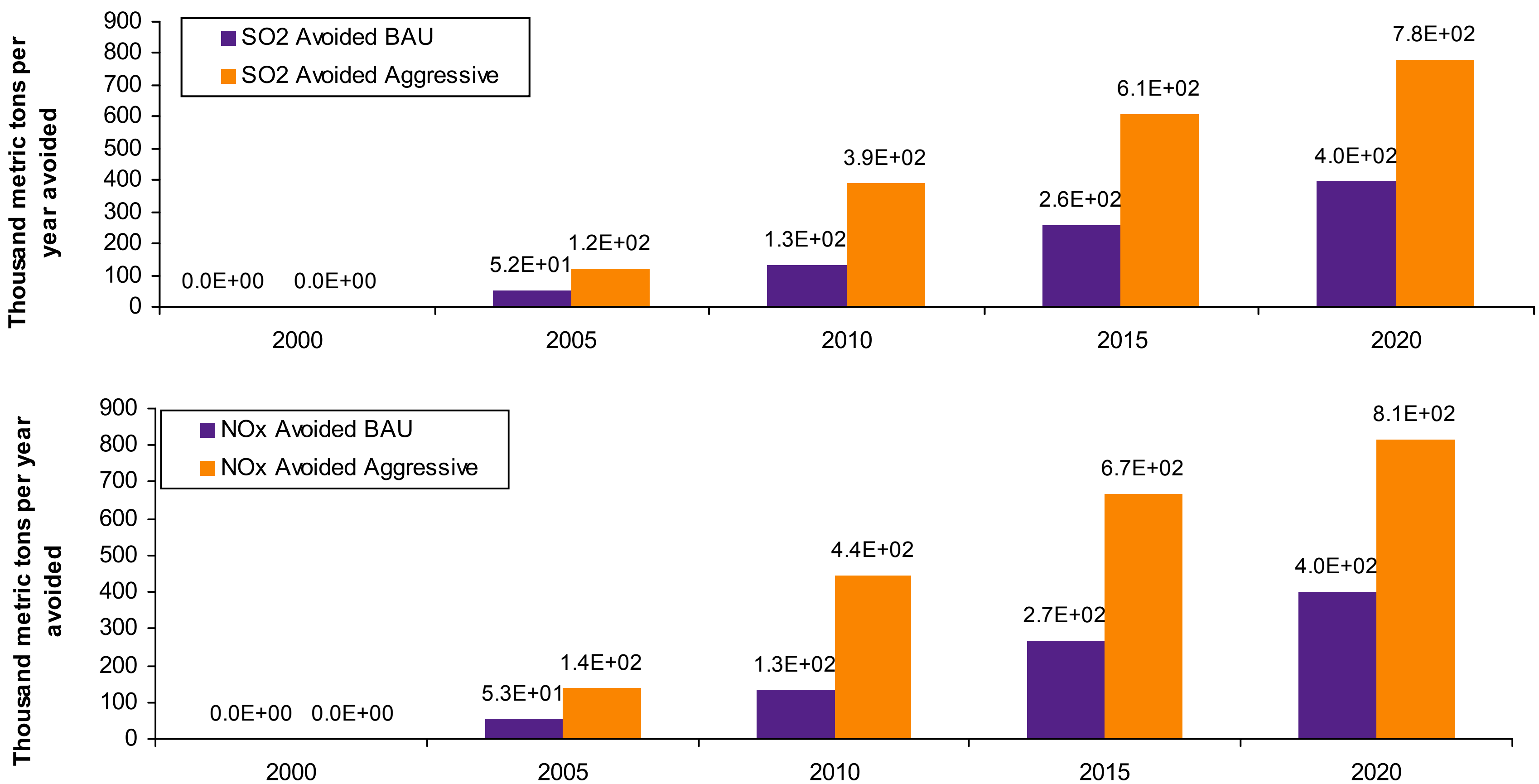
Emissions, Thousand Metric Tons per Year Avoided





Sulfur dioxide and nitrogen oxides are also reduced; mostly by use of low-sulfur biomass and use of co-firing biomass with coal for NOx reductions.

Emissions, Thousand Metric Tons per Year Avoided



In the aggressive scenario, broader application of biomass technology and a more rapid market penetration lead to greater impact by 2015.

Under the aggressive scenario:

- All technologies are introduced commercially by 2010:
  - Successful development and demonstration of gasification technology is required
- All technologies are applied to all relevant feedstocks available
- Technologies can achieve rapid market penetration:
  - Successful and early demonstration of high performance (e.g. efficiency) and low cost
  - Markets value biopower and create pull for green bio-kWhs:
    - Biopower is generally recognized as green power, including biomass co-firing
    - Markets are willing to pay a modest green premium
    - Black liquor gasification is available in time for wave of recovery boiler rebuilds
- To achieve this, aggressive action must be taken:
  - Rapidly enable market penetration of “low-hanging fruits”: biomass co-firing and landfill gas through regulatory reform, and targeted support for the establishment of biomass fuel markets
  - Aggressively promote development and demonstration of higher-risk technologies
- Recent experience with photovoltaics and wind power indicate that renewable energy technologies can sustain market growth rates of 20-40% per year
  - In the case of wind power this has been driven by a combination of green power markets and improvements in fundamental economics
  - In the case of PV, this has been driven by growth in viable niche markets (mainly off-grid) and very strong government support

Biomass power has the potential for rapid growth but requires that several factors combine favorably in addition to very strong government support.

- The largest market is grid-based wholesale power. This requires that the biomass supply infrastructure develop rapidly if the market potential is to be realized
- Biomass co-firing with coal is critical for rapid, near-term growth
  - Direct co-firing using non-woody fuels will likely be required, which will itself require further technology development and demonstration
- Landfill gas and other biogases also figure prominently in the aggressive growth scenario
  - Technologies are available today
  - DOE should focus on removing economic or regulatory barriers
- Other technologies are less important in the near-term but are important for sustained growth
  - The pulp & paper industry represents an important growth area after 2010 via repowering with IGCC
  - Other industries that generate residues are expected to contribute modestly throughout the 2000-2020 timeframe
  - RDF could become a significant source of biopower in the long term, provided technical and environmental issues are addressed successfully
- Gasification for co-firing could become significant beyond 2010, in both coal- and natural gas-fired power plants
- Not included in the scenario is the potential for coal plants to begin retiring. If this begins to happen in large enough numbers beyond 2010, biomass co-firing capacity might actually decrease, unless:
  - These coal plants are re-powered with IGCC technology or replaced with new coal plants, in which case the biomass could be co-gasified or continued to be co-fired
  - The biomass could be used by new, stand-alone biomass power plants or by additional natural gas GTCC plants interested in implementing co-firing

Non-technical barriers to biomass co-firing can and should be dealt with immediately, while simultaneously addressing remaining technical issues.

	2001-2002	By 2003	By 2005
Financial/ Economic	• National assessment of biomass co-firing feasibility (unit by unit) – Business case analysis – Develop software package to facilitate analysis – Proximity to biomass resources	• Support development of biomass supply infrastructure – Encourage large companies to enter – Financial instruments (e.g., futures) – Markets (e.g., "residues.com")	
Technical	• Encourage rapid adoption with proven technology/fuel types while simultaneously working on solving remaining technical issues for other options	• Resolve technical issues with co-firing of herbaceous crops and residues (e.g., switchgrass, corn stover) • Demonstrate biomass gasification co-firing in a coal plant	• Demonstrate biomass gasification co-firing in a GTCC
Regulatory/ Incentives	• Develop incentives to encourage early adopters • Seek green certification for biomass co-firing • Resolve tax credit loophole for "closed loop biomass" • Develop specifications for fly ash that includes biomass content		

Most of the needs for landfill gas/biogas should be addressed quickly so that deployment can be accelerated - no fundamental technology barriers exist.

	2001-2002	By 2003	By 2005
Financial/ Economic	• Improve the understanding of the digester gas market potential to a level similar to the landfill gas market – Business case analysis – Resource assessment • Develop appropriate, modest incentives to ensure competitiveness	• Encourage large energy companies to enter business (could be viewed as part of overall distributed power business development)	
Technical	• Develop packaged power generation solutions suited for a variety of landfill gas and digester gas applications (size, fuel composition) – complement existing product – standardized products	• Resolve remaining technical issues associated with the combustion of landfill gas and other biogases – life – reliability – durability	• Develop commercial fuel cell products to competitively address this market
Regulatory/ Incentives	• More EPA, DOE, USDA coordination on methane mitigation – technology transfer (e.g., landfill gas to digester gas) – private sector involvement across applications – partnerships between power industry, agricultural co-ops, etc. – promulgate standards to facilitate project development	• Promote digester gas and landfill gas conversion as solution to multiple problems – onsite power for reliability and cost savings – waste minimization (e.g., for CAFOs) – Environmental stewardship – Overall grid reliability by encouraging distributed generation	

RDF gasification should be demonstrated in the 2005 timeframe. There should be parallel efforts to remove barriers and educate the public.

	2001-2002	By 2003	By 2005
Financial/ Economic			
Technical	• Targeted technology development/ screening to identify most promising options – Technology transfer from Europe	• Screen suitable sites for RDF IGCC demonstration – Consider retrofit to demonstrate emissions reduction over base technology	• Implement RDF IGCC demonstration
Regulatory/ Incentives	• Education on – Environmental issues of RDF gasification versus incineration – Landfill space crunch	• Consider tipping fee structure or other mechanisms to promote RDF production and utilization • Develop standards to ensure highest environmental performance	

Small-scale gasification of onsite residues could be implemented relatively quickly, whereas pulp & paper applications will take more time.

	2001-2002	By 2003	By 2005
Financial/ Economic	• Develop analysis tool (e.g. software?) to facilitate analysis of the attractiveness of onsite biomass-fueled CHP – Overall plant economics & fit with process – Optimization of residue utilization within plant	• National inventory of Kraft boiler and hogged fuel and bark boilers – Overall attractiveness of retrofit (mill bottlenecks, condition of current equipment) – Assess suitability for retrofit to gasification (age, condition, physical space)	
Technical	• Continue development of small-scale gasification systems, focus on cost-reduction • Develop plan for addressing remaining technical issues in pulp & paper • chemical recovery • gas clean-up	• Detailed assessment of onsite residue generation and use to facilitate optimization of utilization • Commercial demonstration of small-scale systems using various feedstocks and prime movers – internal combustion engines – Microturbines • Demonstrate gasification of hogged fuel and bark in P&P industry	• Demonstrate black liquor gasification at full scale
Regulatory/ Incentives	• Continue strong support of current black liquor gasification demonstrations	• Promote residue conversion as solution to multiple problems – Onsite power for reliability and cost savings – Waste minimization – Environmental stewardship – Overall grid reliability by encouraging distributed generation	• Develop standards & regulations to encourage high-efficiency conversion of onsite residues

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The increased use of biofuels may be impacted by the MTBE debate and continued requirements for oxygenated blend stocks for RFG.

- The focus of the quantitative scenarios was on the technologies that passed through the screening process reviewed in Section 3 of this report
  - Pure fuels focused on ethanol and FT-diesel
  - Blend stocks for a variety of purposes used primarily ethanol
- The BAU scenario assumes that the biomass fuel industry grows aggressively
  - MTBE is banned in California in 2002; the oxygenate requirement is maintained for RFG driving corn ethanol capacity increases
  - Options requiring significant technology development or that face other hurdles are not deployed in the BAU scenario
  - Technology developments (particularly gasification) are adopted with a time-lag after demonstration with biopower grid and onsite applications (not likely before 2020 for fuels use)
- The aggressive scenario leverages developments facilitated by the biopower industry
  - Earlier demonstrations of gasification technology enable gasification based fuels for blending markets
  - Development of a biomass feedstock market and distribution infrastructure
  - MTBE is banned in California in 2002 and in the U.S. in ~2007 and oxygenate requirements are maintained for CAAA affected areas (effectively defining a requirement for ethanol)
- Since these are scenarios, they do not include the full suite of biofuel technologies, but use a variety of options to illustrate what is possible
- We did not include an analysis of a possible import/export market for ethanol

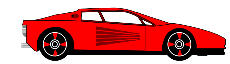
Recent government and industry actions herald a sharp reduction in MTBE use within the U.S.

Year 2000

- **EPA** issued, in March 2000, an Advanced Notice of Proposed Rulemaking that would regulate the use of MTBE under the authority of the Toxic Substances Control Act. The notice does not provide details about how the use of MTBE might be regulated
- As of October 2000, no regulatory nor legislative action has been taken to waive the Federal Oxygen requirement in any state
- **New York and Connecticut** approved an MTBE phase-out by December 31, 2003
- Five other States - Arizona, Maine, Minnesota and Nebraska passed legislation to ban, and South Dakota to limit the use of MTBE within the next several years. The majority of recent legislation has not been linked to an oxygen waiver request. Other States have drafted, but not passed, legislation regarding MTBE use, testing and gasoline pump labeling

Year 1999

- **California** approved an MTBE phase-out by December 31, 2002
- **EPA**'s blue ribbon panel in 1999 recommended a significant reduction in the consumption of MTBE in the U.S.
- **Environmental groups** see pros and cons
  - Air quality wins vs. water quality concerns
  - Public health evidence questionable
- **Industry** is studying the issue, and beginning to take stands
- MTBE bans may spread to other oxygenates, with potential implications for fuel specifications and qualities (e.g. ETBE and TAME)
- Refineries are considering best path forward, cautious of potential legal liability
- Studies are underway regarding potential MTBE carcinogenicity and “developmental and reproductive toxicity”



Ethanol for blending is prominent in the BAU and aggressive scenarios.

Fuels*		Business-as-Usual	Aggressive Growth
Neat ethanol	• Ethanol from variety of resources including corn and cellulosic biomass	• Neat ethanol primarily obtained from corn; restricted to limited fleet use	• Neat ethanol restricted to limited fleet use; feedstocks include corn and cellulosics • Fuel cells penetrate more rapidly
Ethanol for Blending	• Ethanol from variety of resources including corn and cellulosic biomass) • Blending for oxygenate, octane, low-sulfur, and gasoline volume extender applications	• Ethanol made from corn is used in near term for blending; main oxygenate for California MTBE replacement in near term • Ethanol that is made with cellulosic feedstocks comes on-line as development of technology advances	• Ethanol most likely oxygenate for reformulated and oxygenated gasoline • Cellulosic technology development accelerated for increased blend demand for ethanol for California and later total U.S. ban of MTBE • Ethanol production from corn limited by demand/market for feedstock and co-products

* For the purposes of the scenarios, not all technology/fuel combinations have been included. The scenarios are meant to be illustrative.

In both scenarios, ethanol was used in both neat and blending applications.

	Ethanol
Addressable market	Gasoline replacement & blend stock
Target Applications	• Pure fuel • Volume extender • Octane booster • Additive for oxygenates
Production Technology	Fermentation using traditional crops (e.g. corn, wheat) and cellulosics (e.g. energy crops and agricultural residues)

The time required to develop and demonstrate technology and to build plants places significant limitations on the rate of biofuels growth.

Business as Usual

- MTBE is banned in California (~2002) as an oxygenate for RFG and oxygenated gasoline
- The projected lack of cost competitiveness of biofuels for neat applications will slow their penetration into the market place
- Most technologies will require the investment of new plant sections (or new plants) and represent new technology in some cases
- The baseline growth of biofuels will be mostly through corn ethanol for blend stocks until cellulosic plants come on-line

Aggressive Growth

- MTBE is phased out in the United States (~2007)as an oxygenate for RFG and oxygenated gasoline and in California in 2002
- Technologies will be able to capture a greater volume of the growth market
- The improved cost competitiveness of the biofuels combined with existing incentives approach cost parity with other blending agents for oxygenate, octane, low-sulfur and low-aromatic blending applications
- Significant capital and resources are available for aggressive plant construction schedules
- Other options for blending agents are disfavored by market pressures or regulation (e.g. ETBE and TAME for oxygenate blending)

In the BAU scenario, growth is aggressive, primarily from satisfying the oxygenate requirement for California.

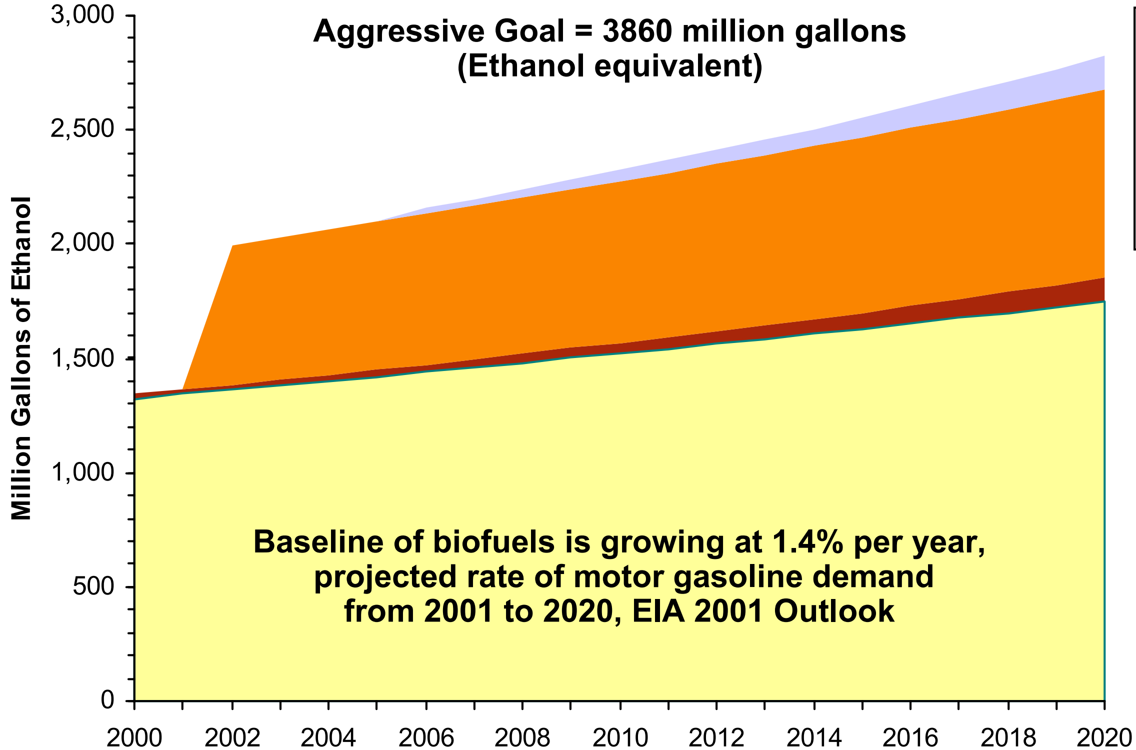
	Pure Fuels		Blending Agents	
	Corn Ethanol	**Cellulosic ethanol**	**Corn Ethanol**	**Cellulosic ethanol**
Percent of addressable market that is capturable*	0.25%	0	75%	75%
Annual market growth rate (%)	1.4	N/A	1.4	1.4
Year of introduction	2000	2006	1975	2006
Time for market saturation (years	60	40	40	40

The EIA 2001 Energy projects an average growth rate in the demand of motor gasoline of 1.4%. The demand for diesel fuel is projected at 2.3 percent. Overall petroleum demand is projected to grow at 1.8 percent. All growth rates are for the period of 2001-2020.

The baseline growth is for biofuels for existing uses as gasohol and octane and volume extender and oxygenate in selected markets.

In the BAU scenario, most of the growth in biofuel consumption will stem from growth in corn ethanol for oxygenate blending for California in 2002.

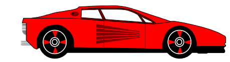
Business As Usual Growth Scenario, Cumulative Installed Capacity to 2020



The size of the near-term market for California (2003) depends upon unsettled requirements for oxygen content in California gasoline, nevertheless, current estimates place ethanol demand in the range of 580 million to 715 million gallons per year ethanol (or 37,834 barrels/day to 46,641 barrels/day ethanol)

COSTS AND BENEFITS OF A BIOMASS-TO-ETHANOL PRODUCTION INDUSTRY IN CALIFORNIA, COMMISSION REPORT, California Energy Commission, March 2001.

Two plants of cellulosic ethanol are operating by 2020.



The vision for the aggressive growth scenario incorporates successful development of advanced technology combined with regulatory stimuli and incentives.

2020 End State

Ethanol

Greater than 750 million gallons of cellulosic ethanol
At least 10 plants in operation using cellulosic feedstocks

Medium-scale conversion technology integrated with blending terminals

Cellulosic ethanol primarily used in blending for octane enhancement and oxygenate content

- Fuel specs require ultra-clean transportation fuels
  - Ultra-low sulfur
  - Low aromatics
  - Oxygenate requirement for diesel and gasoline
- Bio-blend-stocks receive preference over petroleum derived ones
- Green fuel premium is available for neat fuels in niche urban and fleet markets
- Alternative fuel status and tax credits are extended to other bio-derived fuels other than ethanol

Piggy back off biomass infrastructure developed to deliver large quantities of biomass (energy crops, residues) for co-firing

- Large companies involved
- JVs between fuel marketers and agro-companies
- Market mechanisms in place similar to other fuels (e.g., futures, B2B)

FT-Diesel

Medium-scale gasification-based technology integrated with blending terminals

2 Demo FT-Diesel plants

FT Diesel demonstrated as low sulfur blending agent

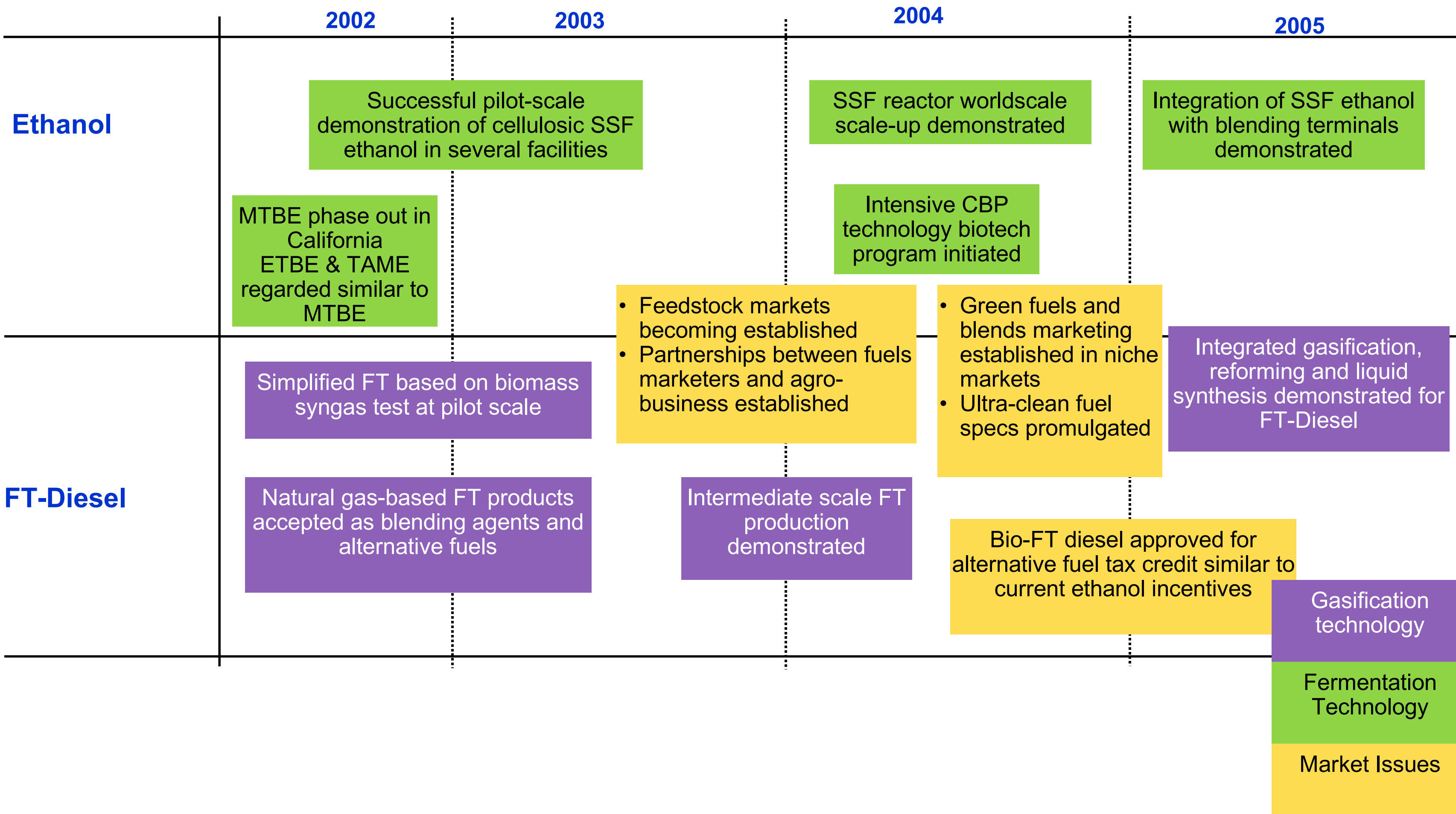
Gasification technology

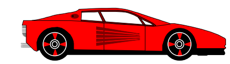
Fermentation Technology

Market Issues

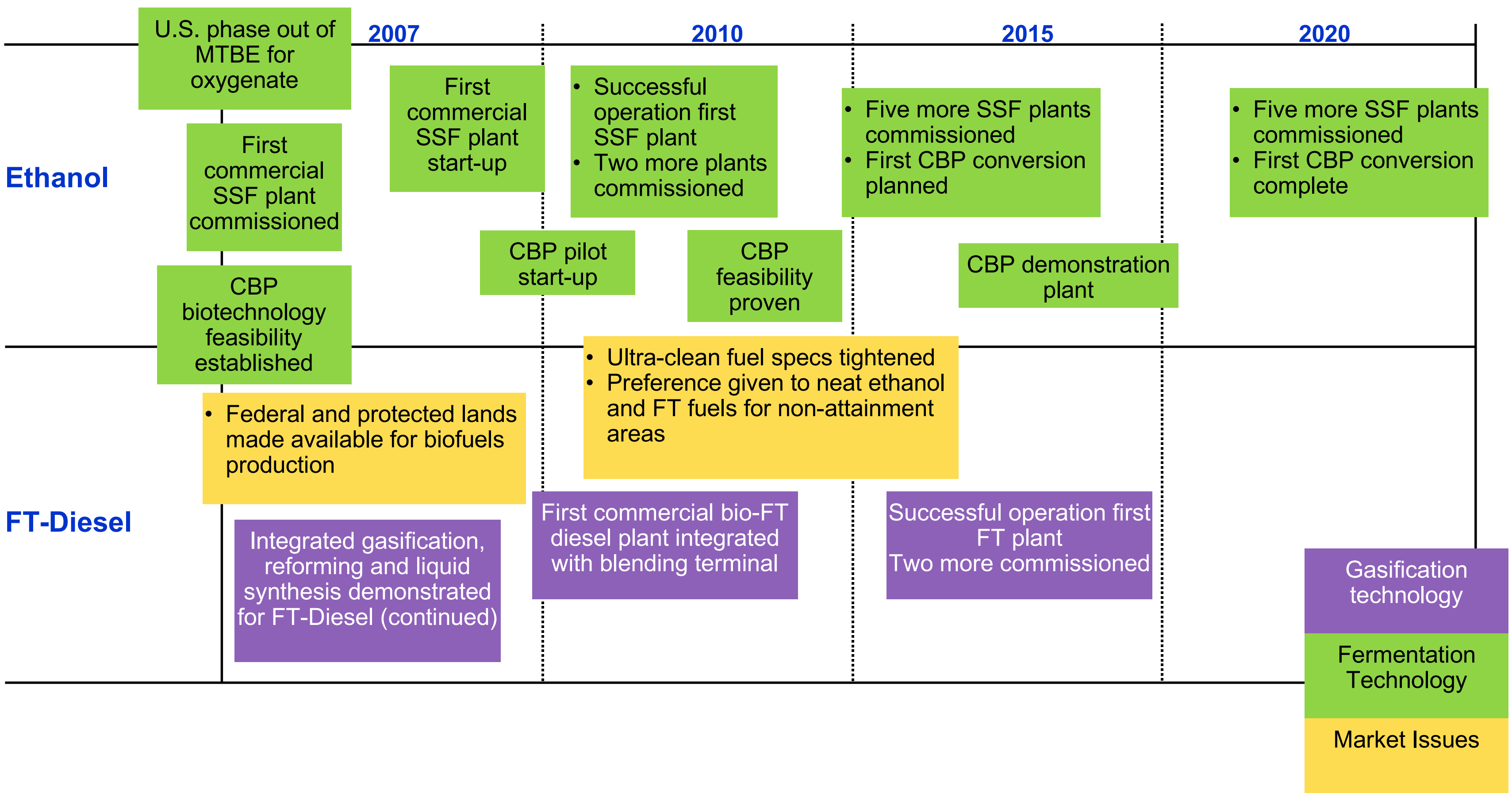
1. We selected 2020 as the year to focus the vision to avoid missing attractive technologies that only barely achieve market introduction by 2010.

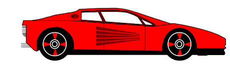
Near-term milestones on the aggressive growth scenario timeline involve mainly technology development and fuel specifications.





In the long term, sustained technology development and supporting regulation and incentives are critical to continued biofuels growth.





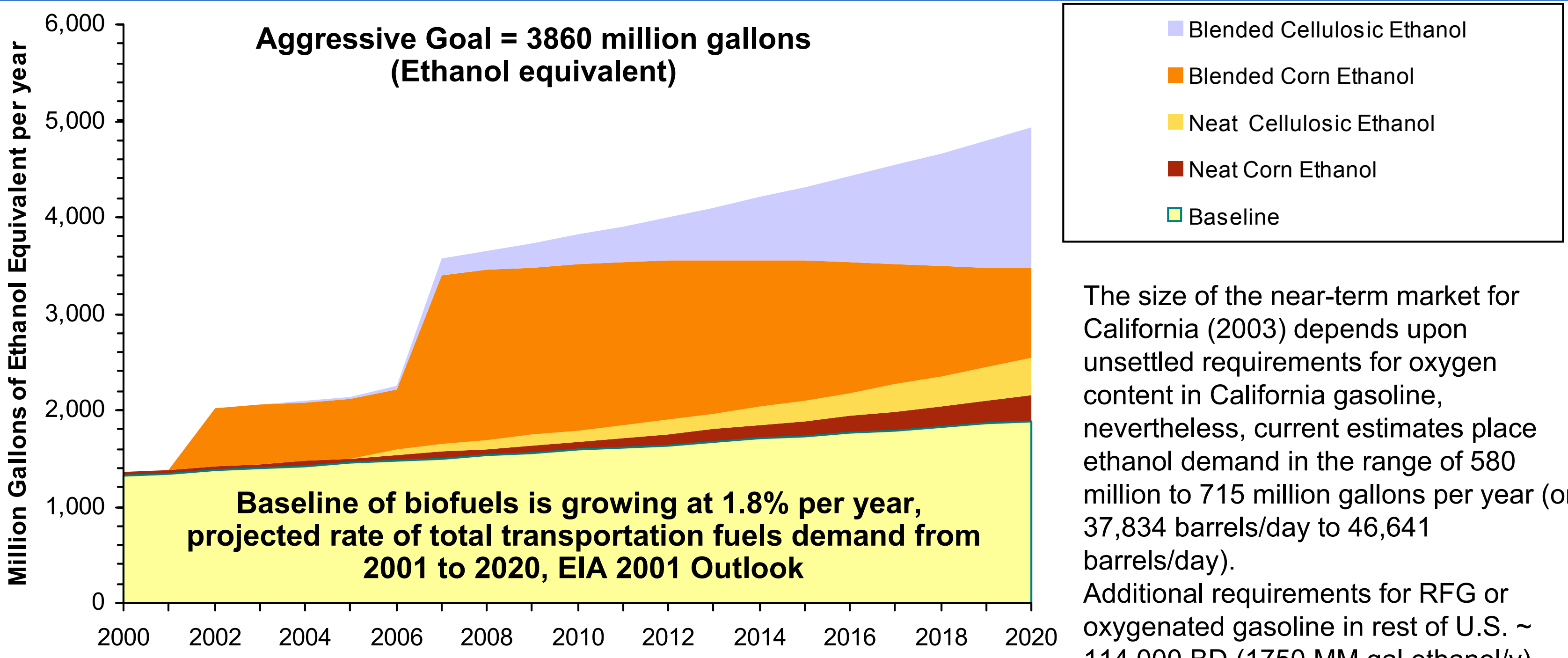
In the aggressive scenario significant improvements in technology and acceleration of the process significantly accelerates implementation.

	Pure Fuels		Blending Agents	
	Corn Ethanol	Cellulosic ethanol	Corn Ethanol	Cellulosic ethanol
Percent of addressable market that is capturable	.25%	0	75	75
Annual market growth rate (%)	1.0	N/A	1.4	1.4
Year of introduction	2000	2006	1975	2004
Time for market saturation (years	60	60	40	20
Comments	• Corn ethanol as a pure fuel is projected to able to address 25% of the market volume corresponding to demand growth • Cellulosic ethanol will likely be used for blending applications rather than as a neat fuel due to projected cost of production • For blending agents, the cost of corn ethanol is projected to limit its use of as a blending agent to half of the demand for oxygenated blending agents • Cellulosic ethanol is projected to be able to address all of the demand for oxygenate and octane blending agents			

The California MTBE ban in 2002 and an assumed U.S. MTBE ban in ~2007 are the major drivers for ethanol market growth (oxygenate maintained).

The aggressive scenario does not meet the 2010 aggressive goal but can surpass it by 2015, requiring significant new plant capacity investments.

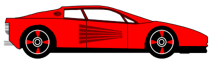
Aggressive Growth Scenario, Cumulative Installed Capacity to 2020



The size of the near-term market for California (2003) depends upon unsettled requirements for oxygen content in California gasoline, nevertheless, current estimates place ethanol demand in the range of 580 million to 715 million gallons per year (or 37,834 barrels/day to 46,641 barrels/day).
Additional requirements for RFG or oxygenated gasoline in rest of U.S. ~ 114,000 BD (1750 MM gal ethanol/y)

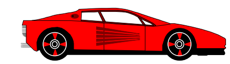
SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE, TECHNICAL APPENDIXES, Technical Documents, California Energy Commission, 1998, prepared by Purvin & Gertz, Inc.

Growth may be limited due to the time and infrastructure (and investment) required to build the new plants and possibly feedstock availability.



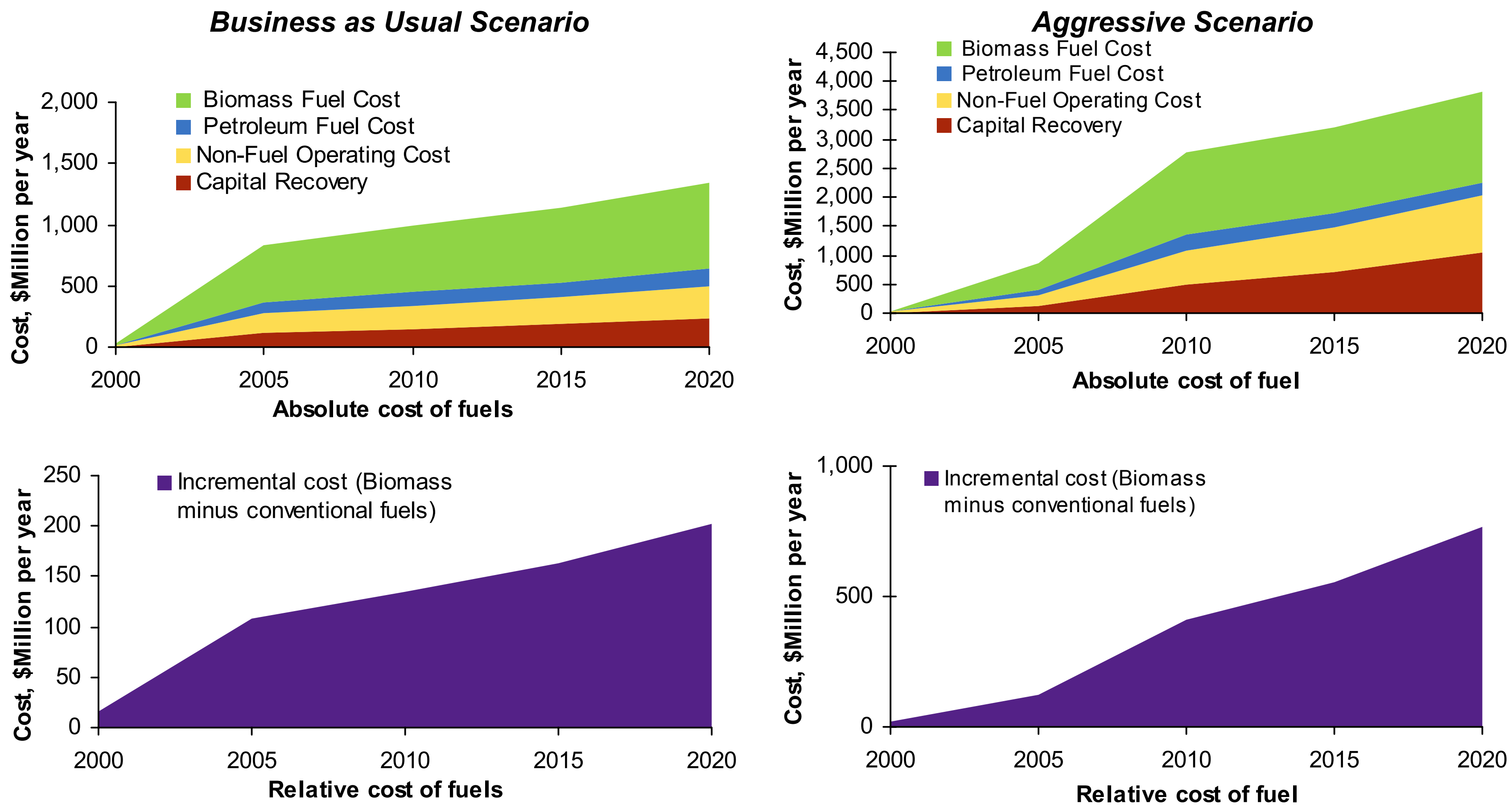
The costs of biomass fuels are mostly associated with the feedstock, capital recovery and non-fuel operating cost.

Assumptions and Methodology	• The BAU scenario assumed a MTBE ban in California in 2002 which drives the demand for ethanol. Oxygenate requirements remain. Gasification fuels (FT-diesel) do not make a contribution • The aggressive scenario took the California MTBE ban and projected a U.S. ban for MTBE in ~2007. An oxygenate requirement was assumed in place • The feedstock cost for cellulosic biomass was $30 per dry ton (farm-gate); corn was $121 per dry ton ($2.92/bu farm-gate) • Blended ethanol price was $1.095/gal (not including tax credit); Premium gasoline $0.96/gal (neat ethanol valued at gasoline value times 0.696 to account for energy density differences)
Comments	• In the BAU scenario, the costs are associated with predominately corn ethanol for blending. It is assumed that cellulosic ethanol comes on line starting in 2006 • In the aggressive scenario, corn ethanol provides the bulk of the demand of ethanol as oxygenate until cellulosic ethanol comes on line in 2004 and capacity is built up. Eventually the ethanol demand is provided by comparable amounts derived from corn and cellulosics • The prices and volumes of comparable fuels were used to estimate the incremental cost associated with implementing biomass fuels, not including any tax credit
Conclusions	• The predominate cost element with biomass fuels is the actual feedstock cost, followed by capital recovery and nonfuel operating cost • In the BAU scenario, the incremental cost of biomass fuels reaches ~$130 MM in 2010 and $205MM in 2020 • In the aggressive scenario, the incremental cost of biomass fuels reaches ~$415 million in 2010 and $770 million in 2020 (not including any tax credits in price of fuels)



The incremental cost in the BAU scenario is ~$130 million in 2010; in the aggressive scenario it reaches $415 million.

Cost per Year to 2020 (Taxes and credits excluded)
Incremental Million dollars per year with $30/dry ton biomass (farm-gate)

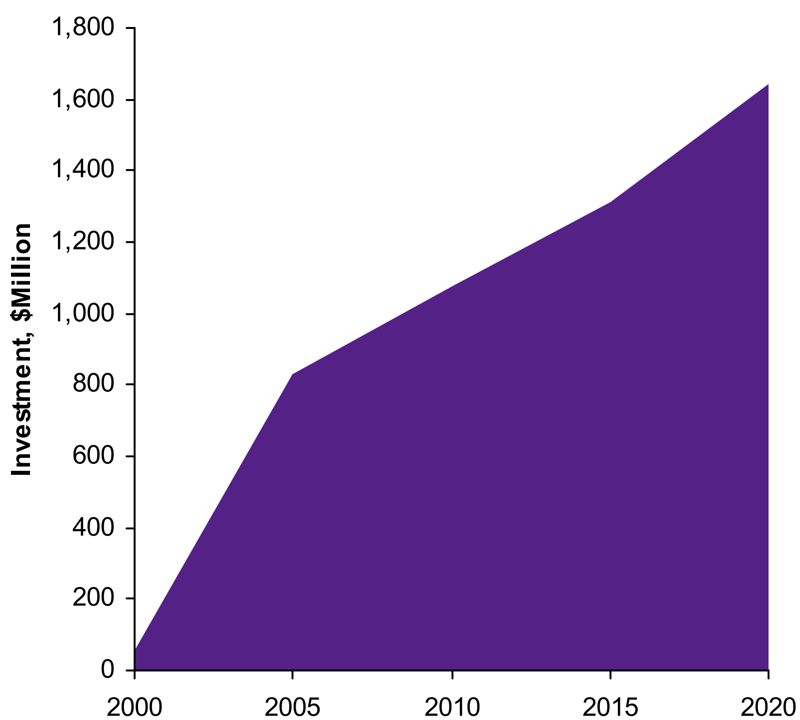


Does not include ethanol tax credit for ethanol price was not included in incremental cost calculation.

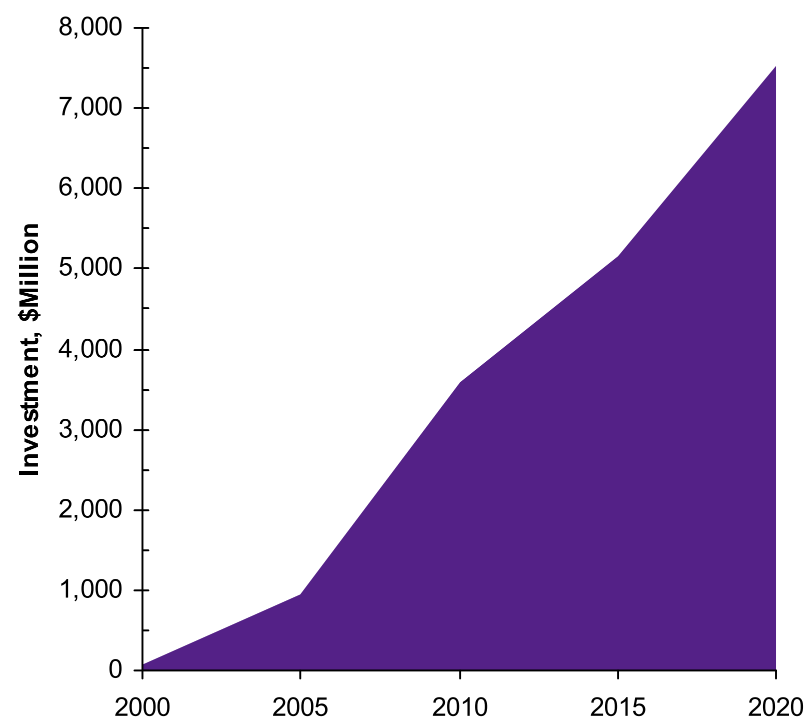
Significant investments are required from 2008 onward as new cellulosic ethanol capacity is built and brought on-line.

Investment to 2020
Absolute Cumulative Investment of Incremental Capacity Above Baseline, Million Dollars

Business as Usual Scenario

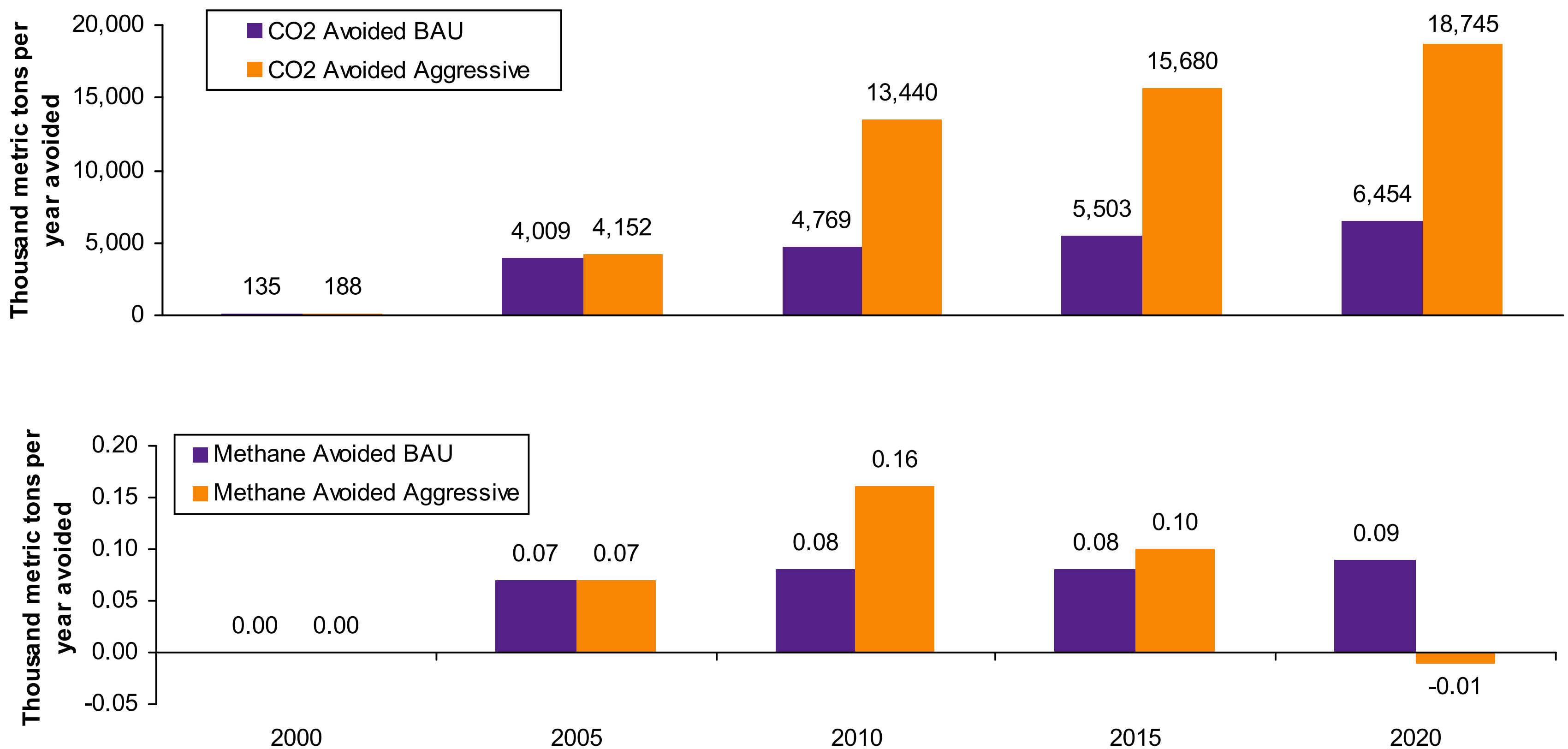


Aggressive Scenario



Biofuels offer significant potential carbon dioxide reduction benefits. All other emissions are on par with the petroleum derived fuels.

Emissions Impact



- The emissions shown are for the incremental (above base line) use of biofuels (mostly ethanol) for blending (mainly oxygenate additive) and pure fuels
- The benefits of additive gasoline has not been taken into account; all priority pollutants generation was set to the emission standard in the vehicle use step

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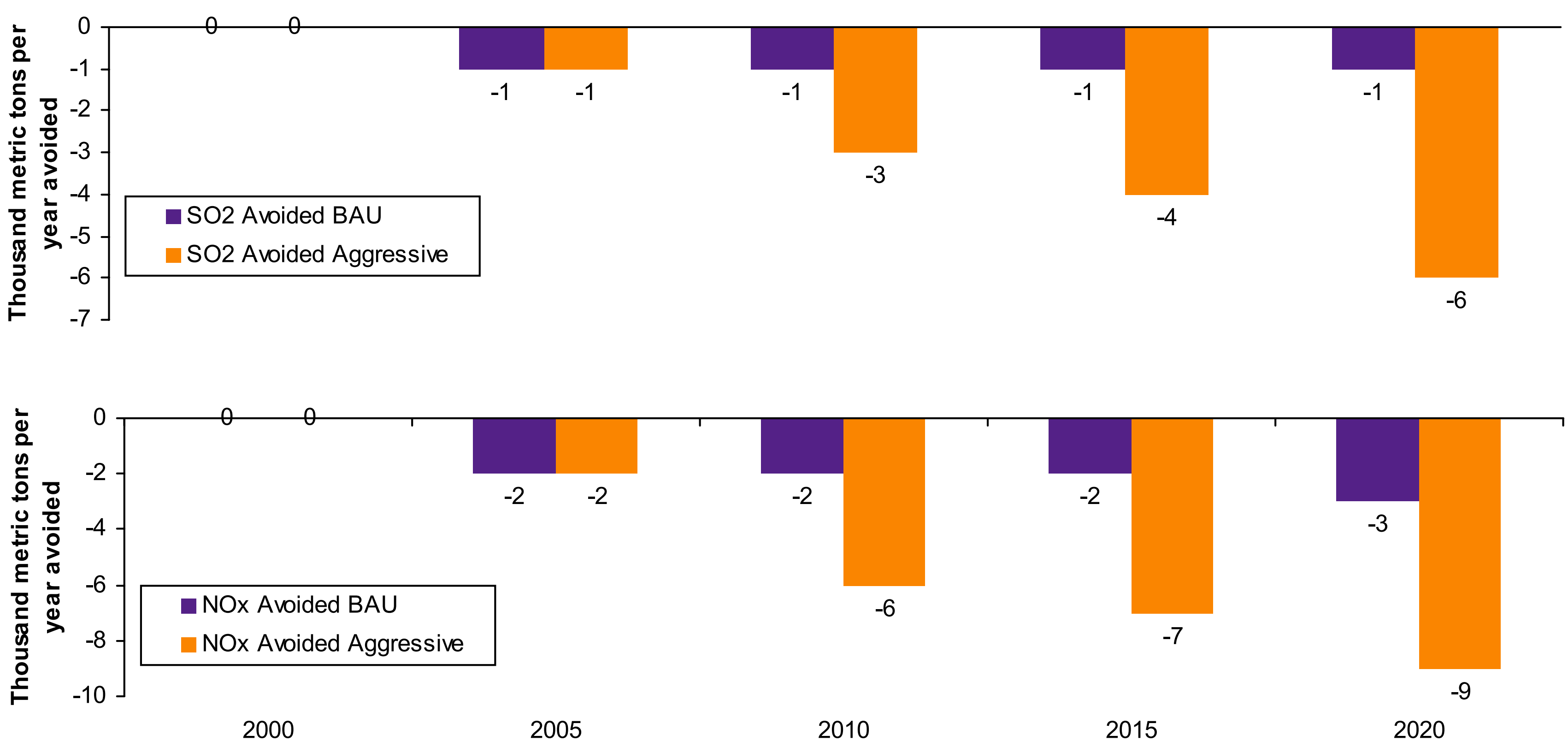
Emissions Impact



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- The benefits of additive gasoline has not been taken into account; all priority pollutants generation was set to the emission standard in the vehicle use step

Tremendous impact could be achieved with the aggressive biofuels scenario, albeit at a high cost.

- In a Business As Usual scenario, increases in production and use of biofuels would be approximately 800 million gallons ethanol by 2010:
  - Limited by current technology cost and government incentives
  - Gasification-based technology is not likely to become commercial
  - Ethanol looks like the preferred MTBE replacement but die is not cast
  - Implementation of ethanol as an MTBE replacement in California is thought to have net positive impact on California economy (but not necessarily on the country)
- Achieving tripling of biofuels use by 2010 would require:
  - Strong regulatory support for bio-derived oxygenates for RFG nationwide
  - Highly successful technology development and cost reduction
  - Highly packaged plants for integration with conventional blending and distribution terminals
  - Continued and stable incentives for biofuel productions
- However, the cost associated with achieving this impact rapidly would be very high:
  - Cost of current bio-ethanol requires a $0.54 per gallon tax credit
  - Additional demand (especially if MTBE were phase out in the nation and an oxygenate requirement remained) would put pressure on ethanol markets and could possibly increase the price
  - Achieving a tripling goal would require construction of cellulosic ethanol facilities based on first generation technology

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE, TECHNinternal combustionAL APPENDinternal combustionES, Technical Documents, California Energy Commission, 1998, prepared by Purvin & Gertz, Inc.

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The increased use of bioproducts will likely be through two avenues initially: carbohydrate based products and lipid based products.

- Aside from wood and paper products (outside scope), most current bioproducts are based on either starch or lipids (seed oils)
- The technology to fully utilize all constituents of cellulosic biomass for products is on par (in development maturity) with fuels technology (other than for power generation applications)
- The options screening analysis indicated that products from fermentation and low-temperature processing had great potential to be cost competitive now and in the near future
- Niche or medium markets may exist to utilize products formed from pyrolysis technology
- Gasification or syngas based products are likely not to be competitive as stand alone units; it is more likely that these products may be made as part of a biorefinery
- Feedstocks for starch and lipid based products are available now and used now for other applications
- A 1998 baseline of 8.7 million tons of bioproducts was taken with a growth rate of 1.8% (constant out to 2020) was taken for both the BAU and aggressive scenarios

Fermentation technology is likely to be key to produce "designer" functionalized monomers for high volume polymer applications.

Products*		Business-as-Usual	Aggressive Growth
Monomers for commodity polymers	• 1,3-propane diol • Lactic acid • Ethylene • Phenolics • Acetic acid	• Most monomers will be produced by fermentation technology which promises high volume manufacture • Monomers will capture volume of market corresponding to growth. Existing capacity will remain utilized	• Most monomers will be produced by fermentation technology which promises high volume manufacture • Cellulosic ethanol may enable bio-ethylene manufacture • Monomers will capture volume of market corresponding to growth. Some market share capture will occur
Lipid based products	• Oil seed polymers • Oil seed lubricants • Paints/Inks • Oleo-chemicals	• Lipid based products are limited in volume by demand of co-products (e.g. Food stuffs, glycerol) • Products will capture volume of market corresponding to growth. Existing capacity will remain utilized	• Lipid based products are limited in volume by demand of co-products (e.g. Food stuffs, glycerol) • Products will capture volume of market corresponding to growth. Some market share capture will occur • New applications are found for new markets
Specialty chemicals	• Water soluble polymers • Solvents • Adhesives/sealants • Oxo chemicals • Antifreeze chemicals	• Most products will be produced by fermentation technology • Lipids and pyrolysis based products find niche markets • Monomers will capture volume of market corresponding to growth. Existing capacity will remain utilized	• Gasification widely accepted as viable technology - leads to gradual deployment starting in 2004 • External environmental factors open new market s for bioproducts (e.g. Green solvents • Products will capture volume of market corresponding to growth. Some market share capture will occur

* For the purposes of the scenarios, not all technology/fuel combinations have been included. The scenarios are meant to be illustrative.

We considered fourteen specific product classes in our scenario analysis (page 1 of 2):

	Monomers for Commodity Polymers					Lipid Based Products	
	1,3 Propane-diol (PTT polymers)	**Lactic acid (Polylactic acid)**	**Ethylene**	**Phenolics**	**Acetic Acid**	**Oil Seed Polymers**	**Oil Seed Lubricants**
Target Applications	• Filament/ fiber • Flm/sheet; • Consumer products • Packaging	• Packaging/ disposables, • Consumer & institutional • Filament/ fiber • Film/sheet • Blown & cast film • Extrusion/ coating; • Injection molding	All applications of ethylene	Possible replacement of 50 percent of petroleum-phenol used in phenol/ formaldehyde resins	• Acetates • Acetic anhydride • Does not include VAM, PTA	Rigid foam and binder replacements	• Industrial hydraulic fluids • Oil field surfactants
Production Technology	Fermentation	Fermentation	Fermentation to make ethanol; dehydration of ethanol	Pyrolysis/High temperature treatment	Fermentation	Oil Seed processing	Oil Seed processing
Stage of Development	R&D/ Demonstration	Demonstration	Early R&D	Demonstration	Market Penetration	Demonstration	Demonstration

We considered fourteen specific products in our scenario analysis (page 2 of 2):

	Lipid Based Products		Specialty Chemicals				
	Paints/Inks	**Oleo-chemicals**	**Adhesives/ Sealants**	**Oxo Chemicals**	**Antifreeze**	**Water Soluble Polymers**	**Solvents**
Target Applications	• Alkyd resins • Resins for lithography, gravure and flexography • Oils for lithography	• Soaps • Detergents • Surfactants • Plasticizers	• Broad range of ingredient substitution and application substitution[1]	• Plasticizer replacement	• Antifreeze • Aircraft deicers	Replacements for hydrocolloids, polyvinyl alcohol, and polyacrylamide	Solvent Replacement[2]
Production Technology	Oil Seed processing	Oil Seed processing	Various Technologies	Fermentation and downstream processing	Fermentation and downstream processing	Low temperature process for starch recovery	Fermentation, oil seed processing
Stage of Development	Market Entry	Market Penetration	Market Entry/ Market Penetration	R&D	R&D	Market Penetration	Demonstration

1. Adhesive replacements include polyolefins, polyurethanes, urea/formaldehyde, acrylics, thermoplastic elastomers, PVC, polyesters, Butyl/isobutyl rubber,furan, nitrile rubber, ethylene-acrylic acid, polyamides, resorcinol-formaldehyde, elastomerics
2. Solvent replacements for perchloroethylene, methylene chloride, acetone, isopropanol, MEK, acetates, trichloroethylene, n-butanol

The premise of the bioproducts analysis is that existing capacity will be utilized looking forward to 2020; bioproducts may capture growth volume.

Business as Usual

- Most target markets are mature markets growing at less than three percent
- Technologies will be targeted towards capturing the volume of market corresponding to market growth
- Most technologies will require the investment of new plant sections (or new plants) and represent new technology and in some instances new applications of the products
- The industries involved are for the most part fairly conservative in their attitude towards new products and new process technology
- The new bioproducts promise improve performance characteristics. The awareness of the improved properties may be low

Aggressive Growth

- Most target markets are growing at less than 10 percent
- Technologies will be able to capture the volume of the growth market plus gain market share captured from competing products
- The bioproduct technologies will be evolved so that some applications will only require the investment of new unit operations rather than whole plant sections (or green field plants)
- The environment for technology trial has been improved so that industries are cautious in their approach to technology adoption
- The performance properties of the new bioproducts are overtly known by both industrial and end consumers.

The assumptions for the business as usual (BAU) scenario are that the bioproducts would capture the growth volume of the market.

- The baseline of bioproduct use is assumed to grow at the projected rate of growth of consumption of petroleum from the EIA Energy Outlook 2001
- The projected market growth rates are taken from the chemical industry literature and are specific for each market
  - A constant growth rate is estimated for each market from 2000 to 2020
- The percent of the addressable market that is capturable is assumed to equal the volume represented by the market growth
  - It is assumed that existing capacity will be utilized and not mothballed or retrofitted
- The year of product introduction is dictated by the stage of development of the technology to produce the product and the stage of application/market development
- Most technologies involve the investment of new plant sections or even new plants
- The products have perceived enhanced performance attributes

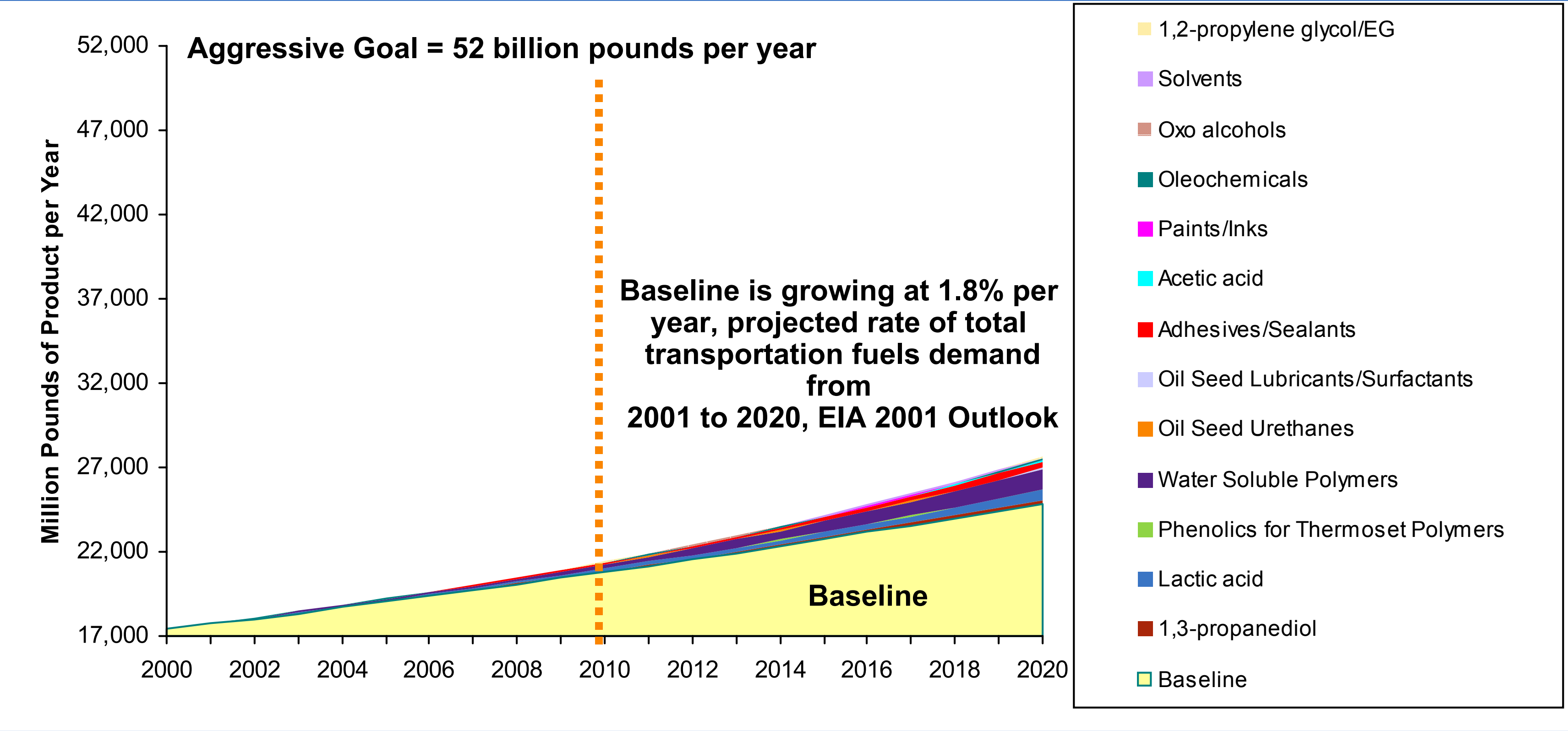
Though most products are expected to reach the market, slow penetration into a limited segment of the market limits impact.

	Monomers for Commodity Polymers					Lipid Based Products	
	1,3 Propane-diol (PTT polymers)	Lactic acid (Polylactic acid)	Ethylene	Phenolics	Acetic Acid	Oil Seed Polymers	Oil Seed Lubricants
Percent of addressable market that is capturable	6.6	3.6	2.5	3.5	3.0	3.0	3.0
Market growth rate	6.6	3.6	2.5	3.5	3.0	3.0	3.0
Year of introduction	2006	2003	2021	2003	2004	2004	2004
Market Saturation Yrs	40	40	40	20	20	40	40

	Lipid Based Products		Specialty Chemicals				
	Paints/Inks	Oleo-chemicals	Adhesives/ Sealants	Oxo Chemicals	Antifreeze	Water Soluble Polymers	Solvents
Percent of addressable market that is capturable	2.0	3.0	4.4	3.0	2.5	2.8	2.0
Market growth rate	2.0	3.0	4.4	3.0	2.5	2.8	2.0
Year of introduction	2003	2000	2004	2008	2008	2003	2003
Market Saturation Yrs	20	10	20	40	40	20	20

The BAU scenario represents an increase of only 3% over the baseline in 2010 and 11% by 2020 due to slow implementation.

Business As Usual Growth Scenario
Million Pounds of Bioproducts to 2020



The BAU scenario reaches 40% of the aggressive goal by 2010 and 50 percent by 2020.

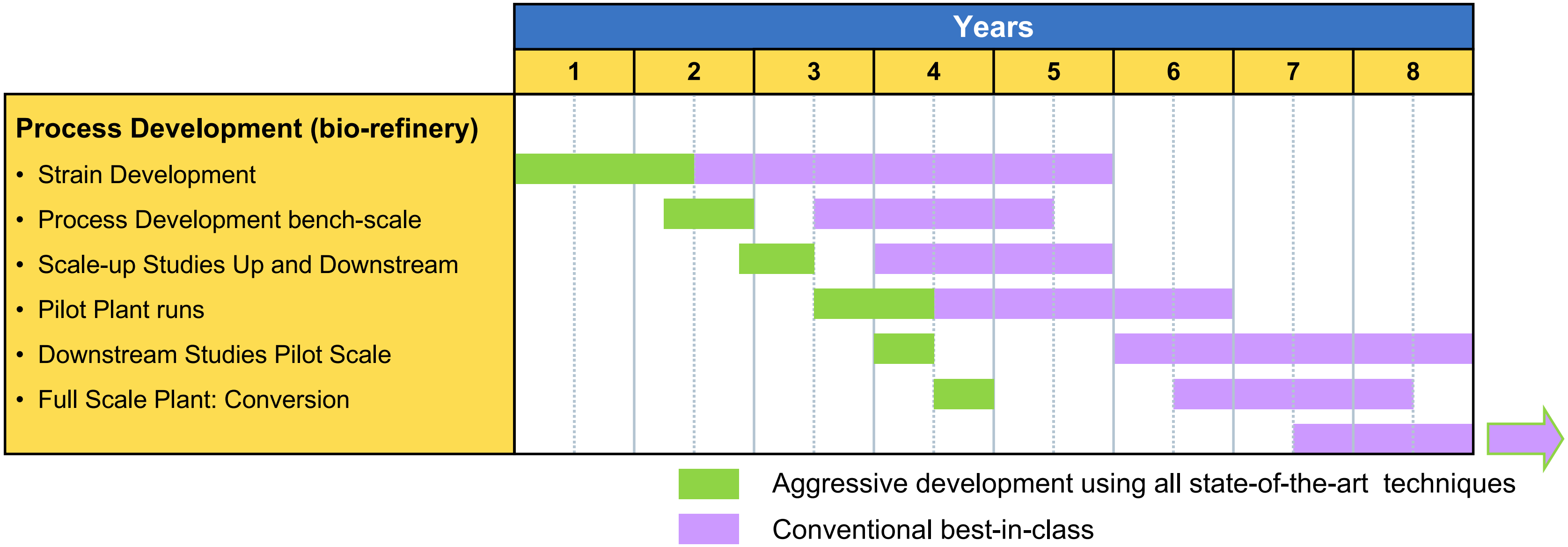
Although some growth in bioproducts can be expected, it represents a small increase due to the slow penetration rates and limited potential market.

- Despite relatively attractive fundamental economics, compared with fuels and power, bioproducts do not have much impact in the BAU scenario:
  - Limited potential market
  - No current large-scale incentives for bioproduct use (such as tax credits for ethanol fuel and green power and other renewable power credits)
- Most of the growth in the BAU scenario for bioproducts comes from traditional bioproduct growth (e.g. starches) and from products produced by physical extraction (e.g. seed oils)
- Technologies with greater potential impact do not reach the market until much later and will penetrate the market slowly

The assumptions for the aggressive scenario are that the addressable market can be expanded and market penetration is accelerated.

- The baseline of bioproduct use is assumed to grow at the projected rate of growth of consumption of petroleum from the EIA Energy Outlook 2001
- The projected market growth rates are unchanged from the BAU case
- The percent of the addressable market that is capturable is assumed to equal the volume represented by market growth plus an additional 10 percent
  - It is assumed that some existing capacity could be retrofitted
- Technology introductions are accelerated when feasible
- The cost competitiveness of bioproducts has been improved so that they are at or approach cost parity
- The properties of the bioproducts, in general, are perceived to be superior to competitive products in selected markets

Utilizing advances in integrated modeling and a full range of data, it is feasible that the development timeline could be cut by about 50%.



- A bio-refinery is an integrated bio-process plant, which has all necessary upstream and downstream modules in place and can be reconfigured to adapt to a given process. Process, scale up and performance data and simulation modules are in place
- Strain development is streamlined by the use of molecular design tools based on genomic data and first principle modeling. Utilizing this approach an organism could be effectively predesigned to have certain input and output traits
- Bench scale process development is aided by modeling and databases. Reaction conditions and media composition are designed from the strain model and the desired input and output traits. Downstream design is aided by a simulation approach using existing purification modules
- Scale-up and pilot plant studies utilize well characterized existing modules and models in the bio-refinery that are adapted to the process input and output parameters
- The bio-refinery's upstream and downstream modules need to be converted to the new process, not completely redesigned

The aggressive scenario focuses heavily on successful development, demonstration, and implementation of fermentation-based technology.

2020 End State

Commodity Bioproducts

Greater than 750 million gallons of cellulosic ethanol At least 10 plants in operation using cellulosic feedstocks

Conversion technology is scale independent and low cost

- Bioproducts are seen as "Green" with enhanced properties that can carry a price premium
- Bioproducts will compete with petroleum products that are biodegradable which is also viewed as "Green"
- EPC industry has developed a new market, construction and operation of large scale bio-processing plants

Piggy back off biomass infrastructure developed to deliver large quantities of biomass (energy crops, residues) for coal co-firing

- large companies involved
- market mechanisms in place similar to other fuels (e.g., futures, B2B)

An incremental 20 billion pounds of material derived from biomass is being produced per year in 2020. Most of the new capacity will leverage fermentation technologies. Growth will continue to leverage existing and new uses for ag products such as seed oils. High temperature processes using cellulosics make specialty products for small to medium volume applications.

The consumers drive the demand for products seen as green.

The processing technology for bioproducts has been significantly improved and seen as clean. Biomass plants are no longer viewed similar to a MSW incineration plant.

Products are:
- Solvents
- Polymers
  - –Propane diol polyester
  - –Lactic acid
- Other organic acids such as citric, succinic
- Paints & inks
- Detergents
- Specialty Chemicals
- Adhesives/Sealants/Coatings
- Polyurethane intermediates (polyol)

Specialty Products

Bioproduct Technology Developments

Biofuel Technology Developments Leveraged

Biopower Market Development Leveraged

Bioproducts leverage the aggressive advances made by biofuels and biopower.

1. We selected 2020 as the year to focus the vision to avoid missing attractive technologies that only barely achieve market introduction by 2010.

In the short term, the aggressive scenario will require a mix of aggressive technology development and facilitation of bio-engineering from a regulatory perspective.

Legend:
- Commodity Technology Developments
- Biofuel Technology Developments Leveraged
- Biopower Market Development Leveraged
- Specialty Technology Developments

2002 | 2003 | 2004 | 2005

Commodity Bioproducts

2002

- Current likely fermentation-based commodity bioproducts are made with simple starch & glucose feedstocks obtained from dedicated & waste streams (e.g. corn mill and food processing waste streams)
- Future fermentation-based bio-commodities may have to use dedicated high-volume cellulosic feedstocks. Programs are put in place to leverage experience gained with cellulosic ethanol organism design

Studies on possible cost savings of co-locating bioproduct plants near existing chemicals, refining, resource, & grain mill plants. Identification of possible shared infrastructure.

2003

Demonstration semi-works plant runs for SSF ethanol technology are conducted

Improved reactor designs for continuous commodity scale fermentation processes at bench to pilot scale

R&D and pilot studies continue with varied feedstocks (e.g.crop wastes, energy crops, woody feedstocks, MSW) to develop operating windows for optimal microorganism (MO) performance using existing metabolic pathways

Develop policy instruments to encourage growth of new resource industry to supply glucose; make glucose the bio-industry "ethylene"

Commodity lactic acid commercial plant on-line

Study on what are the likeliest products that can be derived from existing metabolic pathways Create a wish list of possible "building blocks" that could be made with "to be designed" metabolic pathways

2004

Biomass-based green power is available/offered from new biomass capacity

Engineering MO to make glucose (or derivatives) as feedstock Inter-agency coordination and cooperation on bioproducts development/ road map

1,3-propanediol (1,3-PD) from glucose semi-works plant on-line

Advanced gas cleanup for turbines is proven

Biomass resource infrastructure responds to growing demand for biopower- large companies enter

Start programs that encourage long-term research on utilizing hemicellulose and lignin to produce commodity high-value products. Long term research to use cellulose as feedstock to provide glucose source

Co-ordinate with NIH and NSF for long-term research for new metabolic pathways for promising future "building block" chemicals

2005

Bio-Polymers are a hit for disposables. "Cheap and Green" has resounded with the market

Lactic acid plant-2 online at existing site

Market optimization occurs for use of biomass residues:
- buying & selling ("residues.com")
- onsite utilization (power vs. bedding, vs. mulch, etc.)

Specialty Products

Lessons learned from biopower gasification enable use of syngas based products as part of a biorefinery concept (stand-alone plants not likely to be competitive)

Specialty products derived from seed oils, fermentation processing, and high temperature processing will continue to be developed when the delivered performance and cost offers advantages over competitive petroleum derived products

External instruments will continue to influence the adoption of bioproducts. For example halogenated solvents may be gradually replaced by alternatives that offer price competitiveness and enhanced properties

Additional resources may be required for application development, market development, and necessary infrastructure investments

In the long term, the aggressive scenario will require continued focus on technology development combined with considerable consumer education and leveraging with fuels and power applications.

2007 | 2010 | 2015 | 2020

Legend:
- Commodity Technology Developments
- Biofuel Technology Developments Leveraged
- Biopower Market Development Leveraged
- Specialty Technology Developments

Commodity Bioproducts

- First commercial gasification co-firing in GTCC
- Commercial scale plant (~75 million gal/yr) on-line for SSF cellulosic technology
- Market for lignin for biopower applications established. Uses biopower resource delivery infrastructure
- Aggressive construction schedule to keep up with projected demands, cost competitive with EO derived 1,3-PD. 4 new world scale plants (~300 MM lb/y) through 2020
- 11 Commercial scale SSF ethanol plants on-line
  Market for co-products expanded
- First commercial plant for 1,3-PD using glucose, ~200 MM lb/yr gradually expanding production through ‘12 Improvements through experience are reducing cost towards competitiveness with EO derived 1,3-PD.
- Cellulosic ethanol enables bio-ethylene from ethanol. Aggressive capacity put in place, 1 billion pounds by 2020
- First green-field world scale commodity lactic acid plant online
- Aggressive construction and engineering efforts to keep up with projected demands. Projected demands require building and getting up a plant every year through 2020. Plants with multiple trains located near central resource gathering places. Projected demand of 7 billion pounds by 2020.
- Pilot scale demonstrations of continuous processes using cellulose to make glucose to leverage existing metabolic pathways
- Pilot scale demonstrations of continuous processes using hemicelluose to make glucose to leverage existing metabolic pathways
- Proteomics is leveraged to map new metabolic pathways to produce designer molecules with distinct functionalities for both pharma, specialty, and commodity markets
- Pilot scale studies with new designer metabolic pathways found with aid of existing work with proteomics

Specialty Products

- New markets for glycerol are developing, possible co-feed for bioproduct syntheses
- New product applications and markets are developed using existing biomass sources, mainly ag-products and food waste streams. Cellulosics are being used more and more for new product applications. High-volume applications are identified for possible high volume manufacture

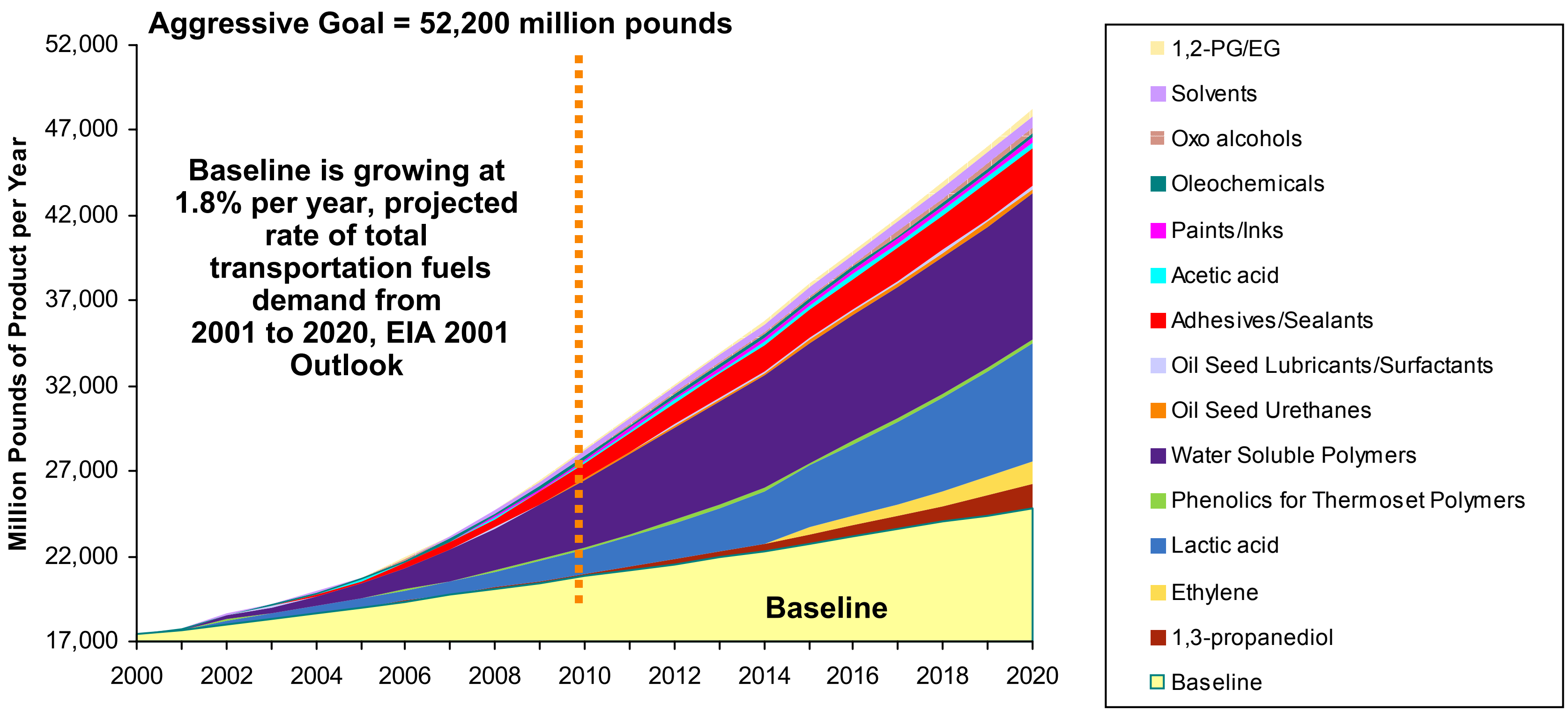
In the aggressive scenario more aggressive market penetration rates and broader capturable markets were assumed.

	Monomers for Commodity Polymers					Lipid Based Products	
	1,3 Propane-diol (PTT polymers)	Lactic acid (Polylactic acid)	Ethylene	Phenolics	Acetic Acid	Oil Seed Polymers	Oil Seed Lubricants
Percent of addressable market that is capturable	16.6	13.6	12.5	13.5	13.0	13.0	13.0
Market Growth rate	6.6	3.6	2.5	3.5	3.0	3.0	3.0
Year of introduction	2006	2002	2015	2002	2004	2003	2002
Market Saturation Yrs	20	20	20	10	10	20	20

	Lipid Based Products		Specialty Chemicals				
	Paints/Inks	Oleo-chemicals	Adhesives/ Sealants	Oxo Chemicals	Antifreeze	Water Soluble Polymers	Solvents
Percent of addressable market that is capturable	12.0	13.0	14.4	13.0	12.5	12.8	12.0
Market Growth rate	2.0	3.0	4.4	3.0	2.5	2.8	2.0
Year of introduction	2002	2000	2002	2006	2006	2002	2002
Market Saturation Yrs	10	5	10	20	20	10	10

The aggressive scenario reaches over 50% of the aggressive goal by 2010 and almost reaches it by 2020.

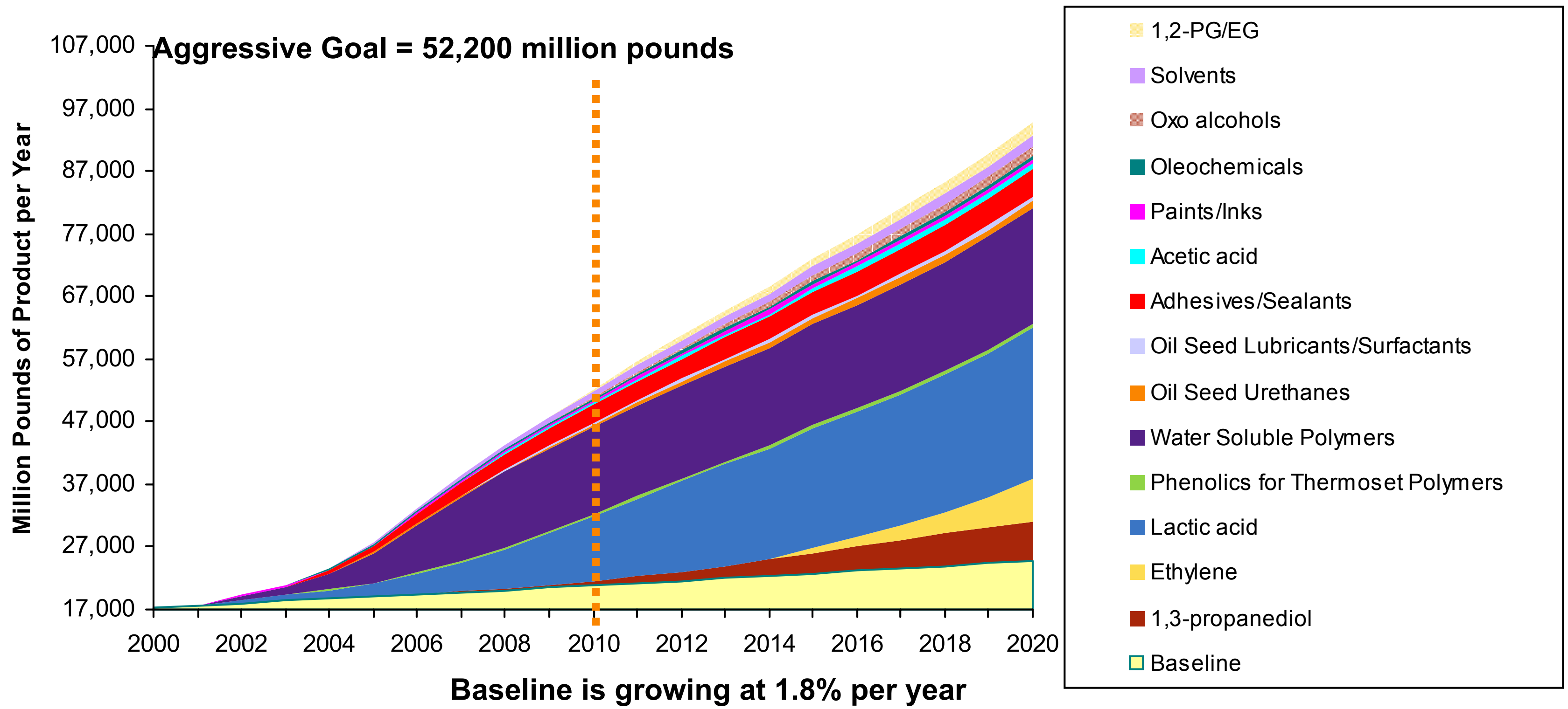
Aggressive Growth Scenario, Cumulative Installed Capacity to 2020



The scenario includes an aggressive plant construction schedule for fermentation-based processes, which will probably have to be combined with SSF ethanol production.

Reaching the aggressive goals by 2010 implies significant increases in the rate of market penetration *and* expansion of addressable and capturable markets.

Aggressive Growth Scenario, Cumulative Installed Capacity to 2020
Reaching the Aggressive Goals by 2010



Reaching the aggressive goals by 2010 for bioproducts is unrealistic just from a viewpoint of capacity expansion rate.

Since there is a wide variety of products in the scenario we estimated the costs of implementation by using three representative costs.

Lactic acid manufacture	Phenolics by Pyrolysis	Oil seed processing for fatty alcohols
• Lactic acid • 1,3-Propanediol • Ethylene • Acetic acid • Solvents • Oxo chemicals • 1,2-propylene glycol and antifreeze/deicing substitutes • Water soluble polymers (starch & cellulose)	• Phenolics • Adhesives	• Oil seed polymers • Oil seed lubricants & surfactants • Oleochemicals • Paints & Inks

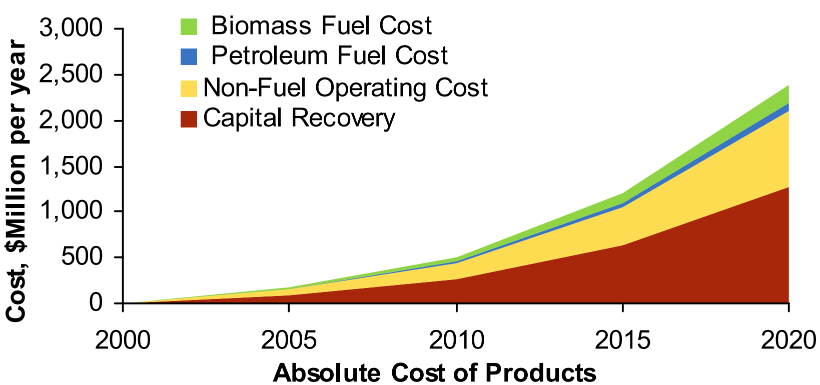
The aggressive use of biomass for bioproducts will highly leverage the use of fermentation technology to build commodity bio-chemicals.

Assumptions and Methodology	• The BAU scenario assumed a negligible advances in bioproducts • The aggressive scenario took aggressive advances in bioproducts into a wide variety of markets • The feedstock cost for cellulosic biomass was $30 per dry ton (farm-gate); corn was $83 per dry ton ($2.00/bu) farm-gate; Seed oil was $340 per ton • The incremental cost of products was estimated by a comparable mass of petroleum products with a value of $0.60 per pound • Assumed all new capacity (green field plants) were built for the new products; did not take into account building next to existing petroluem, pulp&paper, or grain processing facilities that would likely reduce investment cost
Comments	• In the BAU scenario, the costs are associated with fermentation and seed oil products • In the aggressive scenario, fermentation is used to produce both biomonomers, solvent replacements, and a wide variety of products • In the aggressive scenario, lipid based products play an increasing role in selected market segments with relevant applications
Conclusions	• The predominate cost element with biomass products is the capital recovery • In the BAU scenario, the incremental cost of biomass products reaches ~$140 MM in 2010 and $730MM in 2020 • In the aggressive scenario, the incremental cost of biomass fuels reaches ~$1.8 billion in 2010 and $5.0 billion in 2020

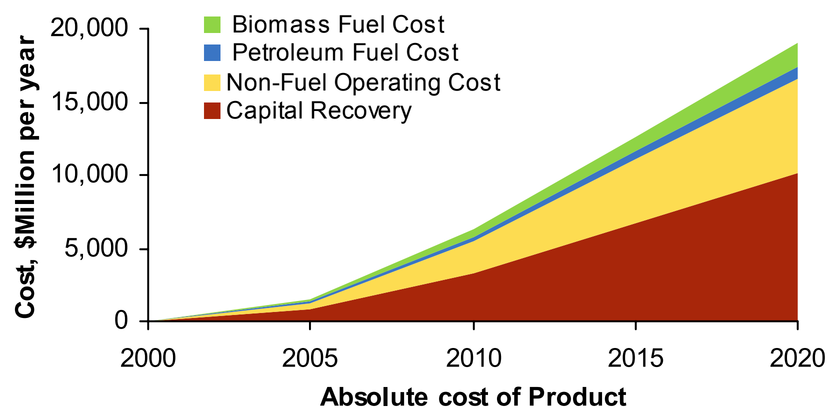
The incremental cost in the BAU scenario is ~$140 MM in 2010; in the aggressive scenario it reaches $1.8 billion when co-products are not accounted for.

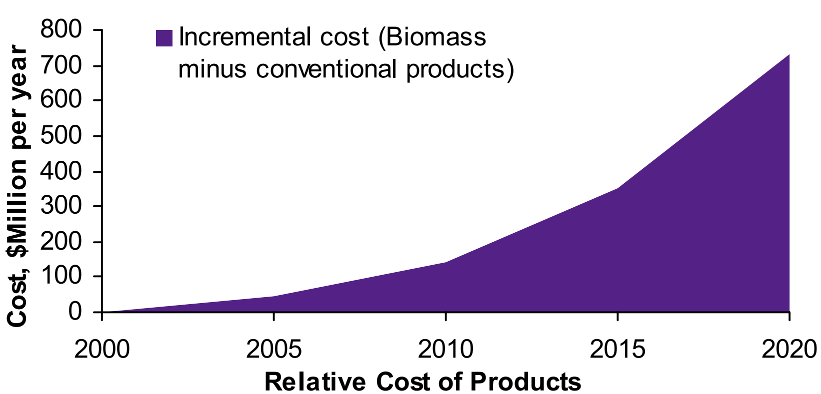
Cost per Year to 2020 (Taxes and credits excluded)
Incremental Million dollars per year using $0.60 per pound petroleum analog products)

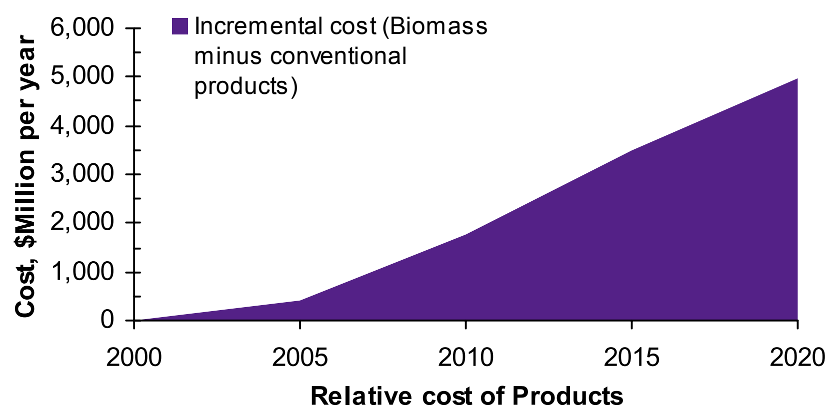
Business as Usual Scenario



Aggressive Scenario

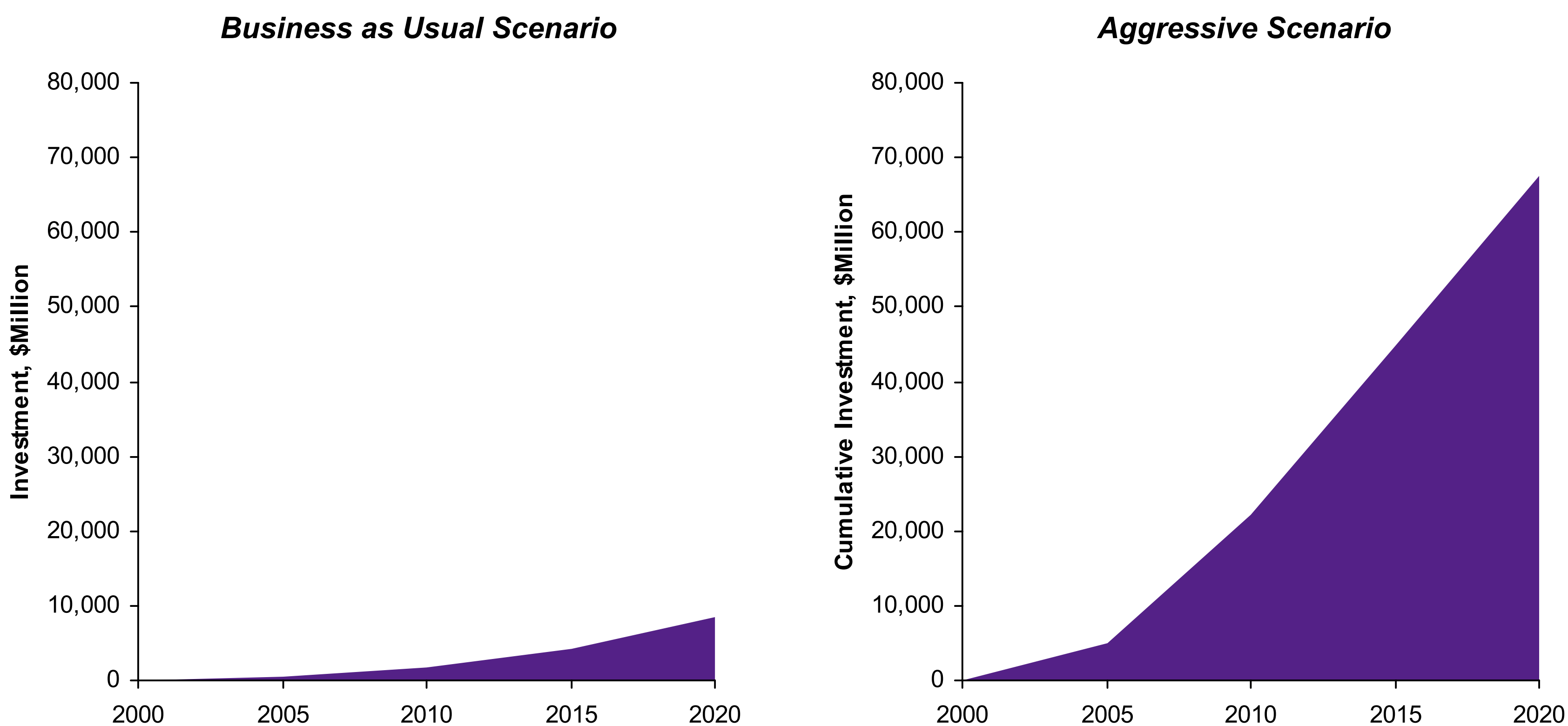






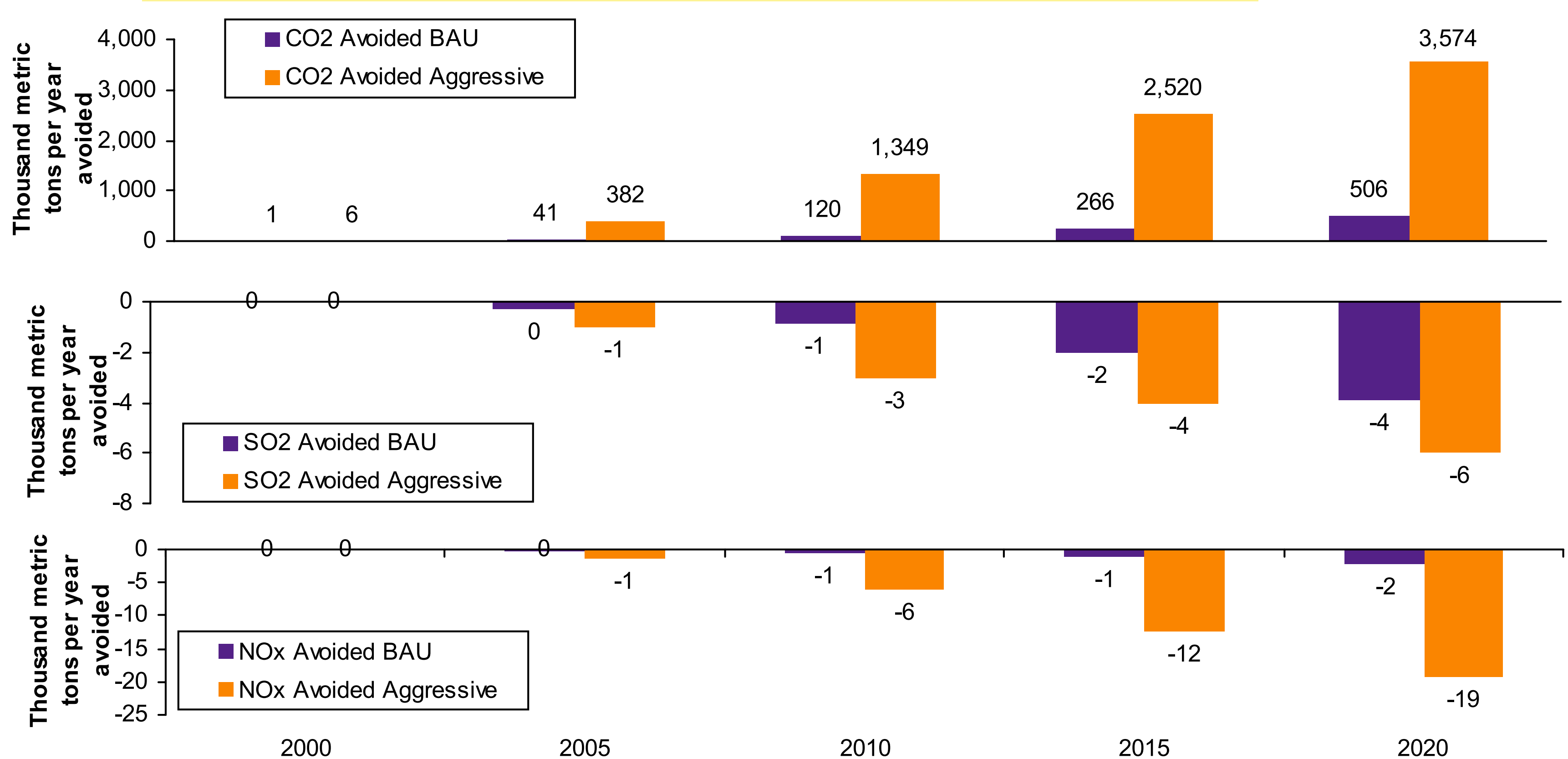
One time investments required for aggressive implementation of bioproducts could reach 20 billion by 2010.

Investment to 2020
Million dollars



Bioproducts offer potential carbon dioxide reduction benefits. All other emissions are on par with the petroleum derived chemicals and products.

Emissions Impact



- This emissions analysis compared the average carbon dioxide emissions against methanol chain emissions on a equivalent mass basis
- This analysis assumed that bioproducts for plastics effectively sequester the carbon contained in the material (e.g. Land-filled and removed from cycle)
- Downstream value chain steps such as derivative product manufacture, product formulation, and distribution, marketing, and end use were not included

Bioproducts use could be tripled by 2020 requiring aggressive technology and market development but not sustained government support.

- In a Business as Usual scenario, bioproducts would capture a small fraction of the growth volume of specific chemical markets
  – No current large-scale incentives for bioproduct use (such as tax credits for ethanol fuel, green power and other renewable power credits)
  – Most of the growth comes from traditional bioproduct growth (e.g. starches) and from products produced by physical extraction (e.g. seed oils), in which bioproducts already have a high market share
  – Limited potential market for low-hanging fruit
  – Technologies with greater potential impact do not reach the market until much later and will penetrate the market slowly
  – Even in the BAU scenario, however, we expect bioproducts to have a considerable impact in the longer term, since competitive economics will be achieved for broad-based application of bioproducts to polymers and solvents
- With aggressive technology and market development and some government support (but not necessarily product price support), a significant impact (even tripling) may be achievable by 2020, though not by 2010
  – Technologies with high impact potential (such as fermentation-based polymers and monomers) would become commercially available in the 2010 timeframe
  – With plant construction and market penetration inertia significant market penetration would not be achievable before 2020
- Given the limited volume of product markets (as compared with fuels and power markets) the relative impact of bioproducts on greenhouse gas emissions and rural economic development can be considerable, but not large in absolute terms
  – Because of the more limited scale, at least early facilities may well be integrated into existing chemicals plants or into existing corn or paper mills
  – The projected economics of bioproducts will eventually not require sustained government financial support for several of the options, resulting in potentially very modest cost for investment, but not for sustained subsidies

This section contains the following topics:

- Background
- Bio-refinery options
- Bio-refinery impacts and role
- Conclusions

Many biomass proponents have argued for the implementation of biomass conversion in bio-refineries, chiefly based on economic arguments.

- In analogy to the petroleum refinery a "bio-refinery" is predicted to benefit from economy of scale and efficiency benefits
  - Co-production of high-value chemicals and pharmaceuticals would help the economics of lower value, high-volume fuel and power products
  - Co-production would allow the economy of scale competitive with oil refineries
- This is clearly true in some cases, as "bio-refineries" are common in a number of industries:
  - World-scale corn mills, food processing facilities, and paper mills often sell a wide range of products, optimizing the overall economics
  - The "high"-value products invariably include foods or paper products
  - In most biofuels and bioproducts production processes co-production of power is considered
- The next section identifies options for applying such concepts to the type of bio-energy and products that fall within the scope of this study:
  - What are the true opportunities created by such bio-refinery concepts?
  - How do they relate to traditional refineries (either petroleum or the biomass-type mentioned above)?
  - What limitations restrict the implementation of "bio-refineries"
  - Which types of "bio-refineries" offer most promise
  - What barriers do they face in their implementation?

Achieving cost effective feedstock utilization and economy of scale are the primary drivers for the configuration of today's petroleum refineries.

- To understand the merit of bio-refineries it is instructive to study the drivers behind the establishment of oil refineries
- Crude oils are complex mixtures of chemicals which can largely be readily separated into various usable products via distillation, maximizing the product value per barrel input:
  - Simple distillation (so-called straight-run refining) can be used to very cheaply separate crude into a host of commodity products (e.g. LPG, naphtha, gasoline, kerosene, gasoil/diesel, fuel oil, bunker oil, asphalt)
  - To efficiently utilize the crude oil and maximize the profit from the products, modern refineries manage to sell around 90% of each barrel of feedstock as some sort of product
  - Markets for these products have been developed over the last one hundred years (recall that gasoline was flared for the first thirty-some years of the industry's life)
- Because crude oil is easily and cheaply transportable, refineries can be built at huge scales, providing significant cost-savings:
  - The minimum scale for a modern refinery is considered to be around 250,000 barrels per day,with the capacity of typical green field refineries overseas in excess of 400,000 barrels per day
  - Most smaller refineries in the U.S. have been shut down over the past decades
    - Too small to achieve economy of scale for individual process units
    - Cannot achieve economy of scale of outside battery limits equipment, notably environmental control equipment
  - For comparison, the largest ethanol plants represent an equivalent scale of a few thousand barrels per day

In principle, similar considerations apply to bio-refineries.

- Biomass feedstocks are made up of several fractions, with distinct properties:
  - Main constituents (e.g. sugar, starch, oils, cellulose, hemicellulose, and lignin)
  - Valuable trace constituents which may either naturally occur or can be bred or bioengineered into crops
- Many of the biomass conversion processes preferentially utilize and reject the same fractions of the biomass:
  - Sugars, starches, oils, cellulose are generally desirable constituents
  - Lignin is generally considered a waste product, at best, suitable for power generation
- To realize the benefits of feedstock utilization, independent uses of each of the fractions must be found
- Similar to most chemical processes, many of the biomass conversion processes would benefit considerably from larger scale implementation
- However, the capacity of biomass conversion facilities is often constrained by the availability of cost-effective feedstock
- Given this constraint, a single-product plant will often provide the greatest economy of scale
- The economy of scale benefits can only be realized for small-volume products or if the biobased facility is integrated with a fossil-based one

We identified five types of "bio-refineries" that could provide some of the efficiency and economy-of-scale benefits petroleum refineries offer.

Improvement in Overall Economy of Scale[1]		Increase in Fraction of Feedstock Converted to Products[2]: Marginal Increase	Increase in Fraction of Feedstock Converted to Products[2]: Significant Increase
	Significant Improvement	**Type-4** Bioproduction independent from fossil production **Type-5** Bioproduction synergistic with fossil production	**Petroleum Refinery** **Paper Mill** **Corn Mill**
	Marginal Improvement	**Type-3** Parallel processing of biomass into different products[3]	**Type-1** Production of co-products inherent in the feedstock **Type-2** Co-products produced from low-value process residues

1. This is the economy of scale of the entire production, in case of a marginal improvement, it might still improve the economy of scale of producing one of the products significantly
2. Referring to the fraction converted into sold products, in many biomass processes, part of the biomass is used to produce power or heat for internal consumption: this is not what is intended here
3. This option could still improve the economy of scale of the production of individual products, although the overall scale remains small

Types 2, 4 and 5 could be combined with others.

These five types of "refineries" differ fundamentally in their characteristics.

	Characteristics	Examples*
Biomass-only options		
Type-1 - Co-products inherent in the feedstock	• Different plant fractions inherently lead to different set of products • No product viable by itself • Analogous to straight-run oil refinery	• Cellulosic ethanol from hemicellulose, power from lignin and other wastes • Masada process with co-product recovery
Type-2 - Co-products produced from low-value residues	• Residue further processed to yield more saleable product • Main product viable by itself • Analogous to high-conversion refinery	• Corn Mill, paper mill that co-produces furfural • Bio-FT diesel plant that co-produces LPG, power-co-production
Type-3 - Parallel production of multiple products	• Only integration of feedstock preparation battery-limit and outside battery-limit (OSBL) infrastructure • Primary benefit economy of scale; only meaningful for low-volume products	• Grain mill producing multiple food products in parallel
Biomass-fossil options		
Type-4 - Bioproduction independent from fossil production	• Integrated with existing fossil facility to reduce infrastructure and OSBL costs • Economy of scale benefits	• Integration of polylactic acid (PLA) production with polyolefins plant
Type-5 - Bioproduction synergistic with fossil production	• Bioproduction and fossil production share mutual benefits • Synergy in downstream processing • Viable for new facilities or facilities with bottlenecks or excess capacity only	• Bio-FT diesel plant integrated with GTL plant

* Potential examples, some of these combinations have not yet been realized

Where achievable, the Type-1 bio-refinery is most likely to provide maximum product value per ton of feedstock input.

Characteristics	• Different products are based on *different* chemical characteristics of feedstock fractions • Products do not compete for feedstock fractions • Benefits of combination of products in single plant are clear compared with each product separately	
Potential Applications	• Typical example is combination of high-value extracted product (e.g. specialty chemical) that occurs at low concentration with high-volume product such as fuel • Most likely does not include more than one fermentation-, gasification-, or pyrolysis-based product (they tend to vie for the same biomass fractions)	
Pros & Cons	***PRO*** • Highest-value use of all feedstock fractions • Could enable use of lower-concentration, high-value products (high-volume product “pays” for harvesting and processing) • Low-volume, high-value products could help provide lift in overall economics • With cross-breeding and biotechnology, high-value products could be bred into crops	***CON*** • Limited number of high-volume products with non-competing feedstock demands • Demand for high-value product may be easily satisfied by single, large-scale fuels plant • Low-volume of valuable products will limit breadth of impact of this option
Barriers to Implementation	• Finding realistic specific product combinations • Combinations may not support more than one plant, making it more difficult to justify development costs • If high-value product is a pharmaceutical ingredient, FDA production requirements may be incompatible with low-cost fuels production	

Type-1 bio-refineries are considered further and should be investigated in more detail by the U.S. government.

Type-2 bio-refineries are likely to be implemented where feasible and could add some additional product value per ton of feedstock input.

Characteristics	• Production residues from main product are used to produce valuable co-products • Implies main product(s) that is/are close to viable on its own • New value in use of residue must exceed alternative use; many residues are proposed to be used for internal power or heat generation, which would have to be off-set by alternative power generation options	
Potential Applications	• Co-product production must be able to use residues • Co-product must be sufficiently valuable to justify additional cost • Likely examples include power co-production from lignin or residue fractions	
Pros & Cons	***PRO*** • Efficient and high-value use of residues • Provides uplift on main product • Likely to be more broadly applicable as primary conversion becomes less and less energy intensive	***CON*** • Many current conversion processes have little true residue that is not already used for internal power or heat generation • Candidate products less likely to be very high value (most likely power, not likely to be high-value specialty chemical or pharmaceutical)
Barriers to Implementation	• Limited barriers, likely to be implemented where possible • Increased plant and project complexity could present issue in first-of-a-kind facility	

Type-2 bio-refineries are already included in the basic option analysis where feasible.

Type-3 bio-refineries are likely to be implemented where feasible but provide limited upside potential in a small number of applications.

Characteristics	• No inherent synergy in production of different products • Benefits derived from economy of scale in feedstock preparation, off-sites, or infrastructure	
Potential Applications	• Technically works with any combination of products • Only provides benefits for products whose production scale is market constrained (rather than limited by feedstock availability)	
Pros & Cons	***PRO*** • Easy to implement (requires no special process integration)	***CON*** • Limited upside potential • Only viable for products with limited markets, thus national impact is expected to be low
Barriers to Implementation	• Limited technical barriers • Small upside potential may limit appeal	

We will not further investigate Type-3 bio-refineries.

Type-4 bio-refineries could be implemented early on to minimize the cost of bioproduction and facilitate product distribution.

Characteristics	• No inherent synergy in production of bio- and fossil- products • Benefits derived from economy of scale in off-sites, downstream processing or infrastructure • Can take advantage of existing infrastructure where some over capacity exists	
Potential Applications	• Should be (and is) considered for chemicals production, notably the production of polymer precursors • Integration of bio-ethanol or FT diesel with existing refineries or blending terminals • Biomass co-firing for power generation	
Pros & Cons	***PRO*** • Could provide significant cost savings on non-process equipment • Facilitates distribution and marketing of product • Could be combined with type 1 or 2 bio-refinery	***CON*** • Requires existing fossil-based facility with expansion potential (e.g. space, systems capacity) • Does not help to reduce process-related cost • May present limited benefit to fossil-based production
Barriers to Implementation	• Limited technical barriers • Small upside potential may limit appeal, especially from fossil-based processing side	

We believe that type-4 bio-refineries should be seriously considered for all but fine chemicals plants.

Where Type-5 bio-refineries can truly be realized, they could be attractive and provide additional impetus for the use of biomass.

Characteristics	• Process and or product synergy between bio- and fossil-based production • Benefits derived from economy of scale in off-sites, downstream processing or infrastructure • Can take advantage of existing infrastructure where some over capacity exists	
Potential Applications	• Bio-FT diesel integrated with GTL plant • Bio-ethanol facility integrated with RFG blending station (possibly) • Requires either new facility or changes to existing fossil facilities	
Pros & Cons	***PRO*** • Provides benefits to both fossil- and biobased production • Could help reduce process related cost • Facilitates distribution & marketing of product • Could be combined with type 1 or 2 bio-refinery	***CON*** • Requires changes to existing fossil-based facility or new facility • True synergy potential is not easily found • At least GTL opportunity may not be realistic in U.S.
Barriers to Implementation	• Increases complexity of plant • Significantly increases the risk of the overall plant, especially for first-of-a-kind plant	

Type-5 biorefineries should be considered seriously but are not likely to be a realistic option in the short term.

"Bio-refineries" are likely to play a key role in the implementation of biomass-derived energy and products.

- "Bio-refineries" could significantly improve the economic viability of certain biomass options, principally by reducing capital cost and improving efficiency
- Only "bio-refineries" where all products truly benefit from the integration are likely to be successful
- "Bio-refineries" are likely to be much more diverse in structure than petroleum refineries
- As such, "bio-refineries" could help in the commercialization of biobased energy and products by broadening its appeal earlier
- Added technical risk and complexity are likely to initially slow down broad implementation of most types of bio-refineries until individual technologies are "proven"

Bio-refineries where true synergy between production processes can be achieved, deserve additional attention.

- Combining biomass-based processes into "Bio-refineries" can offer two potential benefits:
  - Maximizing the value of the products per ton of feedstock (for combining biomass-based processes only)
  - Maximizing the economy of scale of the overall process (for combining biomass-based with fossil-based processes)
- "Bio-refineries" that do not involve any synergy between the production processes may be attractive in some cases, in which case, they will be implemented readily
- "Bio-refineries" that do offer direct synergy between the production processes offer greater potential benefit, but are also more complex and are not well-understood
- The U.S. government could further support the study of such synergistic bio-refineries, but should focus on realistic options

Table of Contents

A 4-step approach was followed to identify appropriate policy options for the DOE to consider in order to increase aggressively the use of biomass by 2010.

1	**Clearly Define Policy Objective**	• Underlying objectives for aggressive biomass utilization • Output versus input basis for biomass use
2	**Review Current Regulatory Environment**	• Establish status quo of regulations on national and regional level • Identify likely changes in regulations
3	**Identify Key Barriers to Objective**	• Cost? • Technology Risk? • Lack of infrastructure? • Consumer education?
4	**Develop & Analyze Options**	• Identify instruments that can be used, given the barriers now in place • Analyze likely effectiveness of options to achieve aggressive growth goals

A clear definition of the policy objective is critical to the identification of strong policy options.

- Poorly-crafted policy can have unintended consequences, and it is therefore critical to define exactly what the goals of the policy are
  - This is most often observed in policies that proscribe technological fixes, rather than setting well-defined goals
- Within a broad policy objective, specific goals may require dramatically different policy tools

Broad Objective	Increase dramatically the use of biomass-derived materials in the U.S. by 2010 (More than doubling of biomass use or products, fuels, and power)

If the specific objective is:	Then an ideal policy option should:
Aggressively increase the use of biomass-derived materials in the U.S. by 2010	• Provide equal stimulus to any technology that produces biomass-derived materials, independent of technology
Bring a particular technology from the laboratory to the market	• Minimize technology development risks to the technology, with successful commercialization (and hence the end of policy support) clearly defined
Create a market for a particular biomass-derived material	• Support any production of the material, independent of technology (and, in some cases, perhaps even independent of feedstock)

Arthur D. Little and DOE identified the underlying policy objectives for the aggressive targets for biomass use.

Broad Study Objective	More than double the use of biomass-derived energy & materials in the U.S. by 2010

To Address the Underlying Objectives...	…the policies options should:
Reduce environmental burden of producing and utilizing energy and products	• Be focused on the environmental end-result, not the path to get there • Address all relevant environmental concerns
Stimulate rural economic development	• Focus on developing competitive economic activity in rural areas, preferably value-added activity
Improve U.S. balance of payments position	• Focus on U.S.-generated biomass (e.g. options should not support import of Indonesian rubber or Brazilian ethanol)
Improve United States energy security	• Focus on pathways that directly offset fossil fuel (e.g., not food & feed or pulp & paper)
Accelerate development of competitive U.S. technology	• Focus on technologies with competitive potential for U.S. industry, not necessarily on ones that are closest to large-scale application • Eliminate barriers for technology development

Both at the federal and state levels there are numerous policies, regulations, and subsidies that directly impact biomass-derived energy and products.

- Many policies are broadly applicable to all renewables
- At the federal level we found that:
  - The 1992 Energy Policy Act (EPAct) is a powerful law to accelerate the use of alternative fuels
  - Existing biopower incentives have not been fully exploited due to stringent requirements, e.g., use of closed loop biomass
  - Several bills had been proposed in the previous Congresses and Administrations, which would have impacted biomass use
  - The Current Administration's focus on a national energy policy promises to take a fresh look at all national energy-related issues, presumably including biobased energy
- There are significant state-to-state variations of policies and incentives:
  - Alternative fuels support from oil overcharge funds or utilities taxes
  - Alternative fuels / vehicle rebates
  - Renewable Energy Trusts / funds
  - Net metering
- We performed a detailed analysis of worldwide policy instruments in use for the promotion of advanced energy technology

* Details of the policy review done are included in the Data volume

The Energy Policy Act of 1992 (EPAct, Public Law 102-486) is a powerful law designed to accelerate the use of alternative fuels.

- EPAct is a comprehensive law that promotes energy efficiency, alternative fuels, replacement fuels, and renewable energy through requirements, incentives, and voluntary programs
- EPAct requires the purchase of alternative fueled vehicles (AFVs) at both the Federal and State level; however, EPAct does not require the use of alternative fuels
  - Executive Order 12844 established guidelines Federal fleets must follow; at least 75% of vehicles acquired by a Federal fleet in any year must be AFVs
  - 75% of light duty vehicles acquired by State fleets must be AFVs in 2000
  - By 2001, 90% of light duty vehicles acquired by covered alternative fuel providers must be AFVs
  - Credits have been allocated to State fleet operators; these credits can be traded and sold
  - States can also apply for Federal assistance to implement AFV programs
  - Federal tax incentives are available to help offset the cost of purchasing an AFV or converting a traditional vehicle to an AFV
- DOE hopes to significantly displace the use of petroleum motor fuels with alternative fuels such as ethanol and biodiesel
  - 10% by 2000
  - 30% by 2010
- The Renewable Energy Production Incentive specified under EPAct applies to a facility for the first 10 years of its operation
  - Incentive of $0.015/kWh for energy produced using closed loop biomass
    - Closed loop has proven to be too restrictive; broadening the definition of biomass to include industrial residues and agricultural waste is under consideration
  - Incentive terminates 20 full fiscal years after the implementation of EPAct (2013), regardless of in service date
- EPAct also lowered the taxes applied to gasohol products based on the alcohol content

EPAct includes specific incentives for the purchase of alternative fuel vehicles and development of refueling facilities.

Program Name	Biofuel Incentive	Value of Incentive
Federal Tax Deduction (through the IRS)	Allows a tax deduction for new, original equipment manufacturer clean fuel vehicles or for the conversion of a traditional vehicle to a clean fuel vehicle Is available for both commercial and personal vehicles and must be taken in the year that the vehicle is purchased Deduction expires on December 31, 2004	• $5,000 for a truck or van with a gross vehicle weight (GVW) between 10,000 and 26,000 lbs. • $50,000 for a truck or van with a GVW greater than 26,000 lbs. or buses that seat 20 or more adults • $2,000 for all other vehicles (except off-road vehicles) • Refueling property is also eligible for an incentive • Incentives will begin reducing after 2001 as follows: – 25% in 2002 – 50% in 2003 – 75% in 2004

In addition to EPAct, several other incentives are currently in place to stimulate the alternative fuel market in the U.S..

Program Name	Biofuel Incentive	Value of Incentive
Transportation Equity Act of the 21st Century (TEA-21, Public Law 105-178)	An ethanol tax incentive is offered under the terms of this Federal highway reauthorization bill. Applies to specific geographic areas. Expires in 2007	• $0.54/gallon in 2000 • $0.53/gallon in 2001 • $0.52/gallon in 2003 • $0.51/gallon in 2005
Small Ethanol Producer Credit	Provides a tax credit for small ethanol producers through December 31, 2007	• Dollar-for-dollar $0.10/gallon credit • Maximum yearly tax credit of $1.5MM (15MM gallons of ethanol)
The Alternative Motor Fuels Act (AMFA) Public Law 100-494	This Federal statute calls for the Federal Government to purchase as many alcohol, dual energy, natural gas, or dual energy natural gas passenger automobiles and light duty truck as is practical	• No specific incentive value
Energy Conservation Reauthorization Act (1998)	Amends EPAct to include biodiesel purchases for use in fleet vehicles that weigh more than 8,500 pounds (gross vehicle weight)	• One EPAct AFV acquisition credit for every 450 gallons of biodiesel containing 20% biodiesel (volumetric)

Sources: Various DOE websites

Existing biopower incentives have not been fully exploited due to stringent requirements, e.g., use of closed loop biomass.

Program Name	Biofuel Incentive	Value of Incentive
Renewable Energy Production Incentive for publicly owned facilities (Specified in EPAct)	Provides an incentive for biopower produced at public facilities using closed loop biomass[1]. Expires in 2003 and is appropriated on a year-to-year basis	• $0.015/kWh
Credit for producing fuel from a non-conventional source	Extends Internal Revenue Code Section 29 provisions until January 1, 2008 for biomass facilities placed in service after December 31, 1992	
Renewable Electricity Tax Credit	Applies to new facilities only	• Up to $0.015/kWh • Incentive is reduced if the purchased cost of power is more than $0.08 or if the project employs government cost sharing
The Tax Relief Extension Act of 1999 (S.1792.PCS)	Extends the biomass production tax credit that expired last year. Extends the in service date to 12/31/92 through 1/1/01 for closed loop, modified closed loop, and biomass co-firing with coal facilities. Biomass includes specific forest products, wood wastes, and crop by-products. MSW and paper do not qualify. Also includes facilities powered by landfill gas and poultry waste that are placed in service between 12/31/99 and 1/1/0. Tax incentives cannot be claimed under Section 29 and this Act	• $0.015/kWh

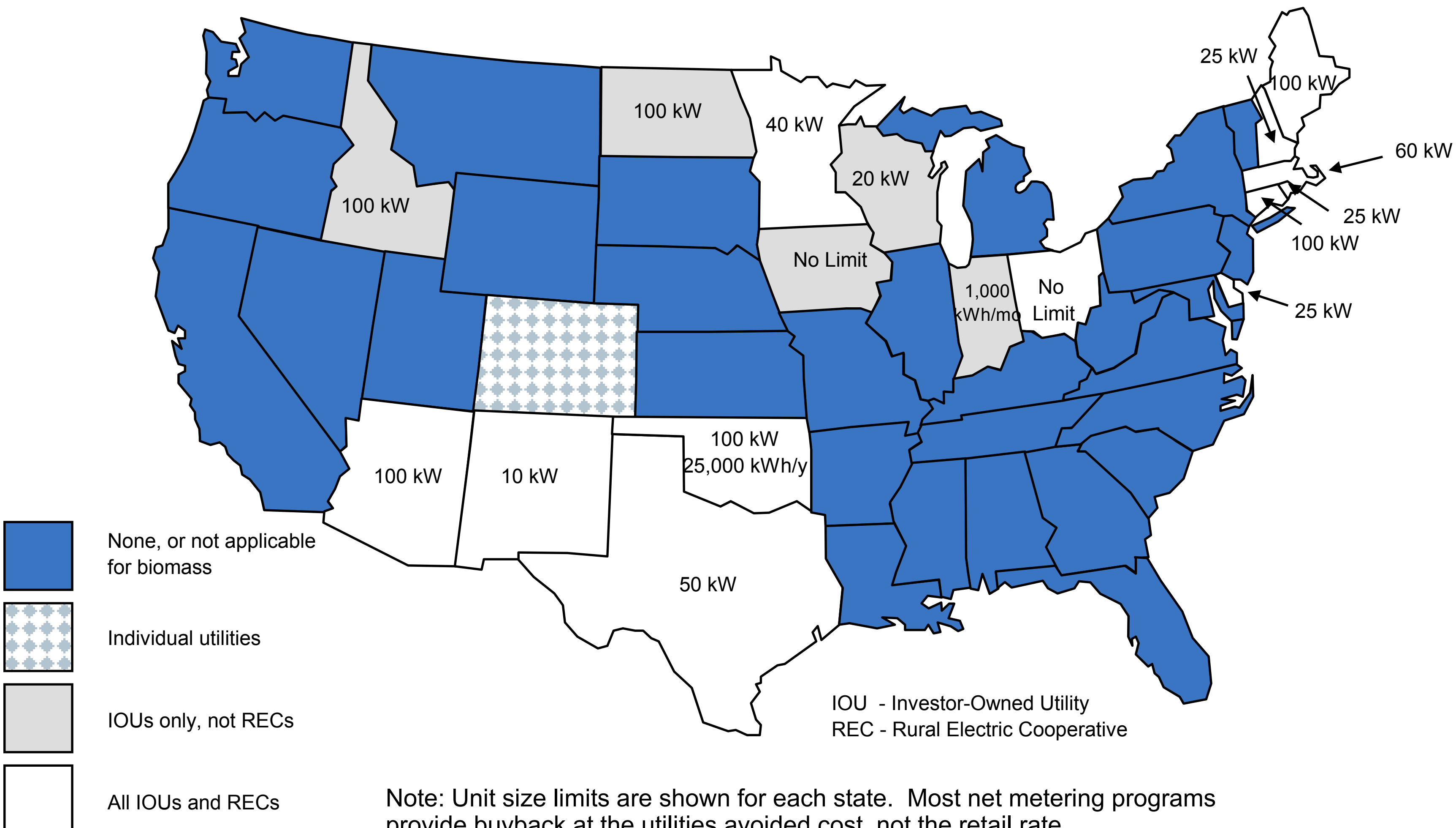
Sources: Various DOE websites and United Bioenergy Commercialization Association.

1. Closed loop biomass refers to agricultural products other than wood that were planted specifically for the purpose of producing electricity.

Funding for state programs that support biomass or alternative fuels comes from industry, consumers, and state agencies.

	Funding Source
Alternative Fuels	Often from oil overcharge funds or utilities taxes
Alternative Fuel Vehicle Rebates	State energy offices, alternative fuels industry, utilities taxes
Renewable Energy Trusts	Systems benefits charges on electricity sales
Net Metering	Electric utilities, ratepayers

Net metering programs that include biomass are offered by 16 states, but are commonly limited to small units.



IOU - Investor-Owned Utility
REC - Rural Electric Cooperative

Note: Unit size limits are shown for each state. Most net metering programs provide buyback at the utilities avoided cost, not the retail rate.

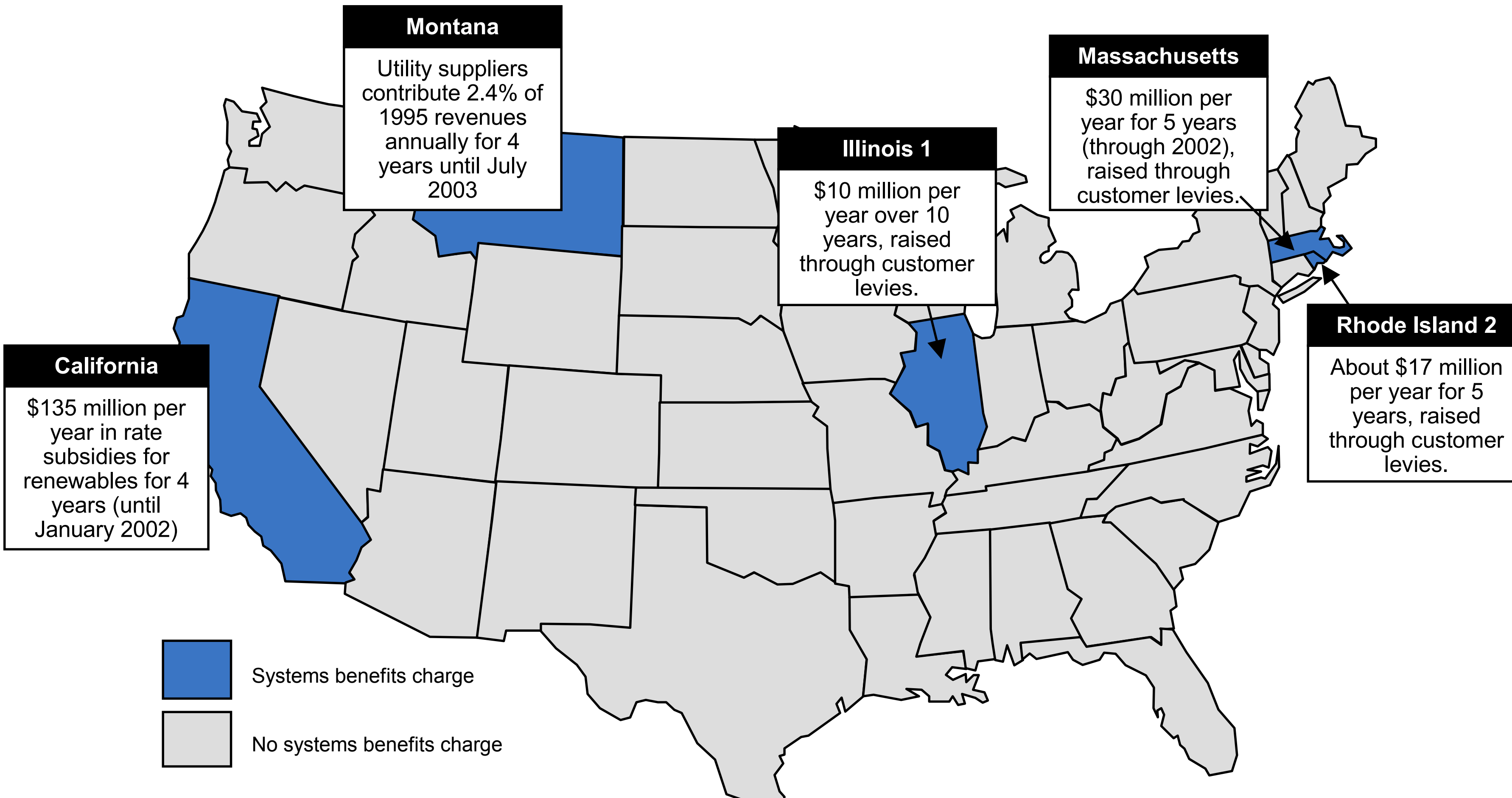
Seven states have developed renewables portfolio standards, which provide non-financial market pull.

State	RPS Provisions	Eligible Resources
CT	Class 1: increase to 0.5% by July 2000, and to 6% by 2009 Class 2: increase to 7% by 2009 from 5.5%	Class 1: New sustainable biomass, landfill gas, fuel cells, photovoltaic (PV) Class 2: Biomass, hydro, MSW
ME[1]	30% of supply must be renewable (includes utility owned hydro)	Biomass, MSW <100MW, fuel cells, tidal, PV, wind, geothermal, hydro, qualified small power and cogeneration
MA	1% in 2003, 4% by 2009, and 1% per year thereafter	Low emission advanced biomass, landfill gas, fuel cells using renewable fuels, PV, wind, and ocean
NV	0.2%, increasing to 1% by 2010	50% from new PV or solar thermal 50% from wind, PV, geothermal, and biomass resources naturally regenerated
PA	2% increasing by 0.5% annually	Biomass, landfill gas, wind, PV, small hydro (MSW does not qualify as biomass in PA)
TX	400 MW new renewable capacity by 2003; 2000 MW total new capacity by 2009	Biomass or biomass-waste products including landfill gas, wind, PV, geothermal, hydroelectric, tidal
WI	0.5% by 2001, increasing to 2.2% by 2012	Biomass, fuel cells, solar thermal, PV, wind, or geothermal

1. Although Maine appears to have set the most aggressive target, it already has 50% renewable capacity (hydro and paper industry biomass), and envisions trading credits in the future.

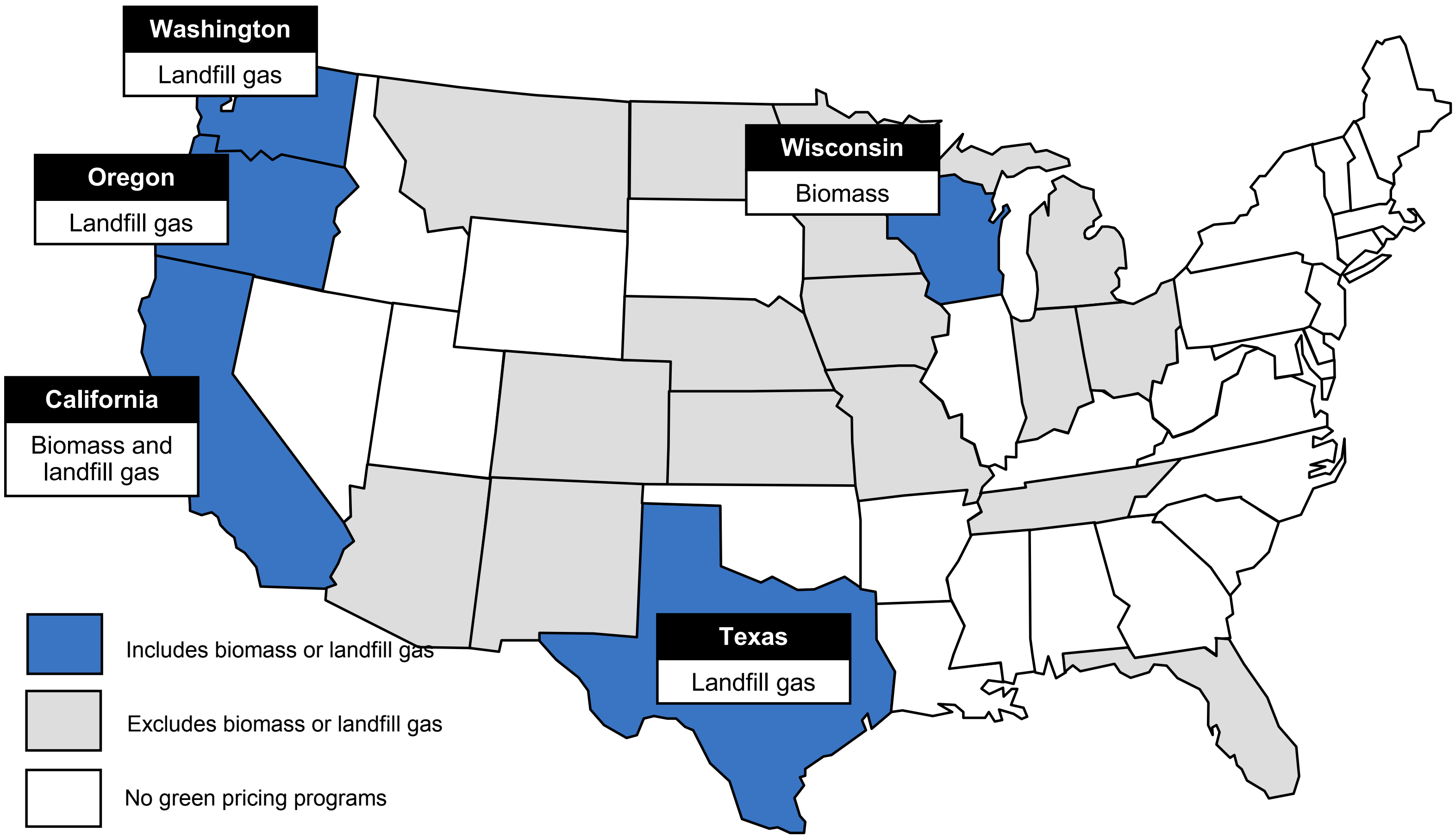
Source: Bioenergy UPDATE, December 1999

Systems benefits charges are established in some states where electric industry restructuring threatens the development of new technologies.



1. Half of Illinois' funds supports renewables, half supports coal technology development. No expiration.
2. Most goes to DSM programs. Only $1 million targeted renewables, including fuel cells, in 1998. Program will be reviewed in Aug 2001

Green pricing programs are offered by utilities in 22 states, but only five states offer programs supporting biomass or landfill gas projects.[1]



1. Most green pricing programs support s wind power, which is close to cost competitive, or small PV projects.
Source: National Renewable Energy Laboratory, 2/2000

Green pricing is offered by individual utilities as a customer service, and is not a state requirement.

State	Utility	Type [1]	Capacity	Year	Value of Premium
CA	LA Dept of Water and Power	Geothermal, biomass, wind	20 MW	1999	0.64 ¢/kWh
	City of Palo Alto	Landfill gas, wind, geothermal, small hydro	8.3 MW	2000	1.2-3.4 ¢/kWh
	SMUD	Landfill gas, geothermal		1997	1.0 ¢/kWh
OR	Pacific Northwest Generating Cooperative	Landfill gas	1.05 MW	1998	1.8-2.0 ¢/kWh
TX	Austin Energy	Landfill gas, wind	40 MW planned	2000	0.4 ¢/kWh
WA	Benton Country Public Utility District	Landfill gas	1 MW	2000	Customer contribution
WI	Wisconsin Electric Power Company	Biomass, hydro, wind	9.8 MW	1996	2 ¢/kWh

1 Most green pricing programs support s wind power, which is close to cost competitive, or small PV projects.
Source: National Renewable Energy Laboratory, 2/2000

Green power markets are emerging as states are deregulated[1], making clear definitions of "green" increasingly important.

- The Green-e certification program was established to provide guidelines for consumers on what power sources are "green"
- Certified provider's products bear the Green-e logo, assuring consumers that the product meets specified requirements and the content is audited annually

Minimum Requirements for Green-e Certification
At least 50% is from renewable energy sources (biomass, including landfill gas, wind, solar, small hydro (generally <30 MW), tidal, ocean, wind, or geothermal) The remainder can be non-renewable, but must have lower SO2, NOx, and CO_2 emissions than your grid supply.

- Participation in the Green-e program is voluntary, so not all green power offerings are "certified"

1 California, Pennsylvania, New Hampshire, and Massachusetts are closest to retail offerings. Arizona, Arkansas, Connecticut, Delaware, DC, Illinois, Maine, Maryland, Montana, Nevada, New Jersey, New Mexico, Ohio, Oklahoma, Oregon, Rhode Island, Texas, and Virginia have passed deregulation legislation

Marketers with Green-e certification will be searching for new renewable capacity, creating potential market pull for biomass-fired plants.

- One year after deregulation, Green-e certified products must contain at least 5% new renewable capacity
  - Requirement increases by 5% each year, until 25% of the product is new renewable capacity
  - New capacity is defined as
    - Operating after January 1, 1997
    - Re-powered after January 1, 1997
    - Improvement or enhancement of an existing facility
    - A separately metered landfill gas resource not used for power generation prior to January 1, 1997

California Companies with Green-e Certified Products	
Commonwealth Energy Corporation	Green Mountain Energy
PG&E Energy Services	Utility.com
Automated Power Exchange	New West Energy
PacifiCorp	SMUD

Green power marketers, in general, represent a direct pathway to market for biomass power projects, although without the strict criteria required of Green-e certified suppliers.

U.S. Green Power Marketers	
All Energy Marketing Company	Essential.com
Bonneville Power Administration	Foresight Energy
Boston Oil Consumers Alliance	Go-Green.com
Calpine Corporation	GreenMountain.com
ComEd	Keystone Energy Services
Community Energy Inc.	Mack Services Group
Commonwealth Energy Corporation	Pacificorp
Conectiv Energy	PG&E Corporation
Edison Source	PG&E Energy Services
Electric Lite	Power Direct
Energy Atlantic	Renewable Energy Alliance
Energy Cooperative Association of PA	Scottish Power
Enron Energy Service	Sun Power Electric
Utility.com	Vestas American Wind Technology

Source: http://www.eren.doe.gov/greenpower/marketing.shtml

Four states offer credits or other financial incentives for new alternative fuels conversion facilities.

State	Type	Program Description	Program Value
Arkansas	Corporate Tax Credit	Designed to promote development of facilities that produce ethanol, methanol, and their derivatives from biomass	30% of the cost of buildings and equipment
Iowa	State Loan	Renewable Fuel Fund has funded six ethanol plants, two soy processing plants, and a methane recapture program for hog farmers	20% grant, 80% loan, up to a maximum of $900,000. Fund receives about $2 million annually
North Carolina	Corporate Tax Credits	Biomass production facility credits	35% of project cost, up to $250,000
Wisconsin	State Grant		$15,000 for technical assistance, $75,000 for construction

Source: Bioenergy UPDATE, April 2000

Only five states offer consumer rebates for alternative vehicle purchases, and two states offer fuel tax exemptions.

State	Alternative Fuel Vehicle Rebates
Arkansas	$1000 to $2000 for vehicle conversions. Federal rebates of $2000 to $4000 are additive
California	$5000 maximum, for new vehicle purchases only
Colorado	$1,500 for passenger cars, $2,500 for light duty trucks, $3,500 for medium duty trucks, and $6,000 for heavy duty
Indiana	$2,000 to $10,000 grants for alternative fuel vehicles (also includes refueling stations, wood waste boilers, and renewables)
Pennsylvania	20% of the cost of AFV, refueling facilities, recharging stations, or vehicle conversion to alternative fuels. $3.5-4.0 million/year is raised from from a utilities tax to fund the program

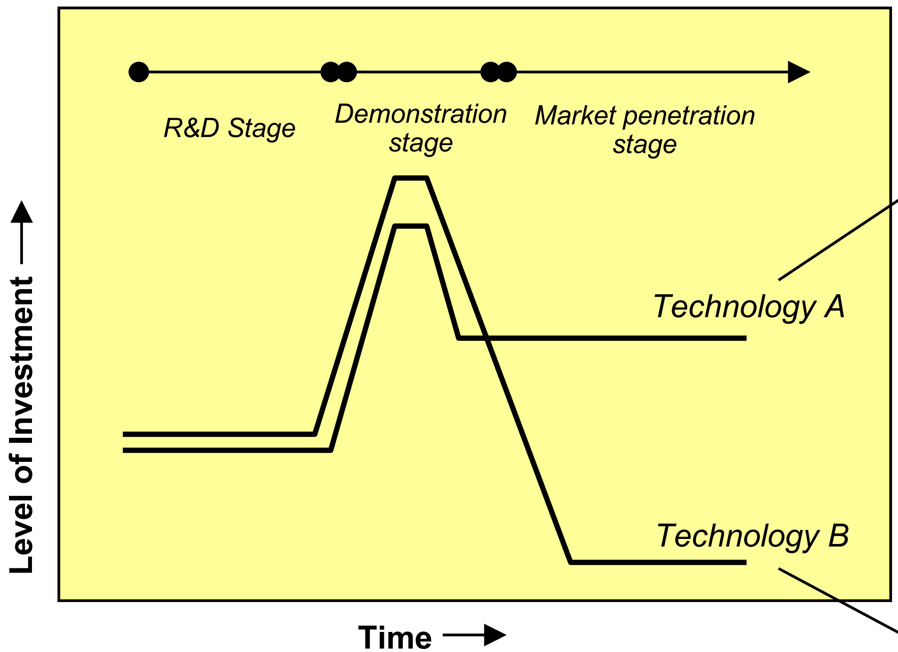
State	Alternative Fuels Tax Exemption
Hawaii	Alcohol fuels tax exemption
Iowa	Ethanol-based fuels tax exemption

We used the analytical tools developed in this study to identify the current barriers to implementation of biomass technologies.

- While the broad objective (more than double biomass use by 2010) applies to all technologies, it is expected that the specific barriers to the implementation of each technology will vary by technology and application
- Some of the barriers that are expected to be significant are shown in the table below

Examples of Expected Technology Barriers	
Technology Development Risk	• New technologies carry risk premiums, with associated rises in financing costs, construction times, acquisition of qualified personnel, etc.
High Cost of Finished Product	• Note that this may be a permanent feature of the technology (e.g., inherently high cost feed stock) or a temporary feature that can be solved with further technology development and production scale.
Infrastructure Limitations	• The introduction of new products that are economically viable, and technically proven may be slowed by the lack of a well-developed infrastructure: for feedstock procurement, product distribution/marketing and/or end-use of the finished product.
Consumer Education	• Consumers may not be aware of the particular benefits of a particular product, thus slowing its market penetration. Consumers may possess disinformation regarding the technology or product.

It is useful to recognize that some barriers are persistent and will require continued government fiscal support, while others require "investments".



This technology requires larger fiscal support after it has achieved market penetration than it did before, suggesting that the sales require steady government support in order to achieve market share. This might result from:

- *Inherently high feedstock costs*
- *Inherent limitations in conversion efficiency*

This technology requires requires a government investment to bring it to market, but once it enters the market, it requires little (if any) sustained government support

Both types of barriers must be tackled in order to achieve significant impact in all segments.

Once these barriers are identified, it is possible to classify the policy options to spur their implementation.

Barrier	Sample Policy Options (Partial List)
Technology Development Risk	• Bench-scale R&D to improve technology • Co-funding of pilot plant construction and/or operation • Publicity of early successes • Favorable tax/depreciation treatment for first-generation plants • Access to low-cost capital • Access to personnel
High Cost of Finished Product	• Subsidized prices (e.g., ethanol credit) • Cross-subsidies from competing products • Note that subsidies may be permanent (type A) or gradually phase out (type B)
Infrastructure Limitations	• Subsidize the development of an infrastructure • Bring together industrial partners to develop infrastructure (e.g., California H_2 program) • Develop codes and standards for infrastructure
Consumer Education	• Publicity/education

Barriers to technology implementation were identified from the comparison of the BAU and Aggressive growth scenarios, as well as the impact analysis.

Examples of Potential Barriers, by Stage of Development Impacted

Type of Barrier	Research and Development: *Component R&D*	Research and Development: *Initial System Prototypes*	System Demonstration: *Refined Prototypes*	System Demonstration: *Commercial Prototypes*	Market Entry	Market Penetration
Technical	• Low efficiency • Low durability • High cost	• Unit operation compatibility • Thermal integration issues	• Operation in "real world" conditions	• Proof of durability	• Provide performance desired by market	• Incremental technology advances
Economic	• Materials selection • Efficiency	• High balance of plant (BOP) costs	• Identify path to lower costs	• Develop manufacturing techniques	• Maintenance & service cost • Access to affordable fuels	• Incremental cost reduction
Market	• Markets often not identified	• Markets often not identified and/or poorly characterized	• Identify "early adopter" markets	• Develop marketing strategy	• Unacceptable return • Feedstock availability	• Publicity • Consumer education
Political / Regulatory	• Lack of R&D tax credits	• Lack of R&D tax credits	• Identification of relevant codes & standards • GM standards	• Siting & permitting issues (compliance with C&S); GM standards	• Subsidies to competing technologies	• Inconsistency of regulatory environment (state versus Federal, etc.)

Biopower | Biofuels | Bioproducts

We identified five key categories of barriers that most impact all categories of options.

	Fundamental Technology Barrier	Cost not Acceptable	Address Early Adopter Markets	Poorly educated consumer	Regulatory Barriers
Biopower	• Gas cleaning for BIGCC must be improved • Design & eng. guidelines for co-firing implementation don't exist	• Cost of stand alone biopower is too high	• Black liquor gasifiers face market conservatism	• Biopower not seen as really green • RDF / Waste-to-energy seen as an "incinerator"	• Fly-ash regs for co-firing are restricting • Deregulation uncertainty • Biomass feedstock markets not well developed • New Source Review
Biofuels	• Organisms for CBP (consolidated bioprocessing) ethanol not robust • Gas cleaning for Bio-FT not adequate	• Cost of all options more than 1-2 times as expensive for fuel value of products	• Oxygenate markets prove difficult to substitute ethanol (market, infrastructure issues)	• Value of green fuels not recognized	• Ethanol credit only extend to all renewable fuels? • Limitations on GMO R&D and production
Bioproducts	• Fermentation-based commodity-scale production not well developed • Large-scale reactor technology not developed	• Cost of current technologies may still be too high for early adopter applications	• Need early markets for fermentation-based feeds	• U.S. consumer not very responsive to green branding • Competition with "biodegradable" fossil derived products	• Product standards for new chemicals not yet established • Limitations on GMO (genetically modified organism) R&D and production
Biomass Feedstock	• Recalcitrance of cellulosic biomass for applications other than power	• Biomass low energy density makes transportation costs key issue • Harvesting, yield	• Pulp & paper expand power production • Ag residues for more revenue for farmer	• Biomass equated with MSW; "garbage" • Biomass utilization plants perceived as "dirty"	• Markets for biomass not well developed • Competition among biomass forms (ag wastes vs energy crops)

Broadly speaking, there are eleven categories of possible policy support options for advanced energy technologies (1-5).

Option Category	Examples	Type of Support	Target Development Stage
R&D Support	• R&D grants • Salary support for qualified scientists • Student grant support • National lab programs • Corporate R&D tax credits • Establishment of public/private R&D partnerships	**Investment**	**R&D**
Direct Subsidies	• Investment subsidies • Alternative fuel / AFV subsidies • Product subsidies • Farm product price support • Land-use-related subsidies	**Sustained support**	**Market Penetration**
Risk Sharing	• Financing Renewable Energy & Efficiency • Loan guarantees • Project insurance	**Investment**	**Demonstration - Penetration**
Funding Demonstration Projects	• Clean coal • Publicly funded demonstrations	**Investment**	**Demonstration**
Benchmarking & Best Practice	• Competitive benchmarking • Non-competitive benchmarking • Energy-based benchmarking • Best practice forums • Audits	**Investment**	**Market penetration**

Broadly speaking, there are eleven categories of possible policy support options for advanced energy technologies (6-11).

Option Category	Examples	Type of Support	Target Development Stage
Voluntary Agreements	• Gentlemen's agreements • Covenants • Public/private partnerships	**Investment/ Sustained support**	**R&D - Market Penetration**
Risk Sharing	• Financing Renewable Energy & Efficiency • Loan guarantees • Project insurance	**Investment**	**Demonstration, Market Entry, Penetration**
Standards, regulation, Deregulation	• Regulation rationalization • Utility deregulation • Renewable portfolio standards • Green certification	**Investment / Sustained Support**	**R&D - Market Penetration**
Infrastructure Investment	• Government investment in infrastructure	**Investment**	**Market Entry, Market Penetration**
Tax Measures	• Investment tax credits • Depreciation benefits	**Investment**	**Market Entry, Market Penetration**
Information Provision	• Consumer awareness programs • Technical information exchange programs • Industry workshops • Networking events • Training activities	**Investment**	**R&D - Market penetration**

Mapping the potential policy options against key barriers and considering their cost-effectiveness can help compare policy options.

Option Category	Absolute Cost	Typical Cost-Effectiveness	Effectiveness in Addressing Key Barriers				
			Fundamental Technology Barrier	Cost not Acceptable	Address Early Adopters	Poorly educated consumer	Regulatory Barriers
R&D Support	$	+++	+++	+	-	-	+
Direct subsidies	$$$$$	---	-	+++	+	-	-
Risk Sharing	$$$	++	+	++	++	-	-
Demonstration Projects	$$	+	-	-	++	-	-
Benchmarking / Best Practice	$	++	-	+	-	-	-
Voluntary Agreements	$$	++	+++	+	+++	+	+++
Standards / (de-) regulation	$	+++	+	+	++	-	+++
Infrastructure Investments	$$ / $$$$	+/-	-	+	+	-	-
Tax Measures	$$$	++	++	+++	++	-	-
Information Provision	$	+++	-	-	+	+++	-

Breakthrough Energy Technologies for Industry, Phase II Report, for Nederlandse Organizatie Voor Energie en Milieu. Arthur D. Little 1997

Sustained support of globally uneconomic options may still be sensible from a national or regional perspective.

- Sustained support for a given option clearly costs the state significant sums in subsidies, price supports, tax credits etc.
- However, that cost can be off-set wholly or partially by economic benefits to the region:
  - Switch from imported to home-grown products
  - Investment in industry creates jobs
  - This all creates extra tax revenue which could be used to fund the subsidy partially

A selected set of policy options appear to be critical to achieving success in implementing increases in biomass use.

- R&D support is critical to achieve the necessary and sustained breakthrough improvements in technology performance and cost
- Voluntary agreements and public/private partnerships are critical to marshalling the level of resources necessary for large-scale implementation efficiently
- Tax measures can be used to entice early adopters and or bridge the cost-competitiveness gap for selected biomass options
- Information programs and consumer education programs are critical to internalizing the benefits of biobased energy and products in terms of product premiums
- Direct subsidies or price controls are likely the only way to have a chance at achieving the tripling goal can be achieved by 2020 in all sectors
- If, for example, similar tax credits as in ethanol were provided for biopower and bioproducts, significantly larger impacts could be achieved in these categories, of course with considerable added cost too
- Sustained support, while not desirable from a global, free market perspective, may in fact be sensible on a national or regional basis

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Overall, the opportunities for biomass-derived energy and products are considerable with environmental benefits and increased value-added activity.

- In the near term, and with modest additional cost, considerable impact can be achieved by focusing on a number of attractive options, primarily in biopower
- In the longer term, significant impact can be achieved with the further development of some higher-risk technologies
  - This impact takes the form of reductions in greenhouse gases and other pollutants
  - Increased domestic production of natural resources consumed in the U.S.
  - Increased high-value economic activity in rural areas
- Achieving a doubling or tripling of use of biomass energy and products is possible by 2015 or 2020
  - The development of new production and conversion technologies and the application to new markets could lead to this impact overall, and in each of the biomass use categories (power, fuel, and products)
- However, we recommend that the U.S. government carefully weigh the rate of increase in the use of biomass-derived energy and products against the cost
  - We believe that attempting to achieve rapid doubling of biomass energy and products use at all cost (e.g. by 2015) will lead to the application of technologies that could be superseded by superior and more cost-effective technologies only few years later
- Thus, we believe that a somewhat more long-term view of the biomass opportunity which allows for the development of technologies that could become commercial in the 2010-2020 timeframe, would be beneficial, and may lead to a more optimal use of resources for the benefit of the nation

With sufficient investment and government support, significant increases in the use of biomass energy and products in the U.S. by 2010 are feasible...

- Sufficient biomass is expected to be available in the U.S. to more than double its use but prices at high volume are expected to exceed $20/dry ton farm-gate (~$1.1/GJ; $1.2/MMBTU)
- Several significant implementation options appear nearly ready for commercialization, provided a supportive regulatory and tax environment for their early implementation:
  - Biogas-to-power (e.g. landfill gas) and biomass co-firing with coal provide competitive ways to increase biopower capacity by over 100% by 2010 (additional 11,000 MW) from today's biopower capacity levels
  - Increased use of bio-ethanol as a gasoline oxygenate, it alone represents a potential 50% increase (additional 2 billion gallons) in use by 2010 from today's biofuel consumption (provided the current tax credit is continued and the oxygenate requirement in RFG remains)
  - Fermentation-based monomers, pyrolysis-derived phenolics and lipids offer near-term opportunities for increasing bioproducts use by over 40% from today's use (additional 7 billion pounds product by 2010)
- When looking out to 2020, additional long-term options exist to significantly expand that impact:
  - Biogas-to-power (e.g. landfill gas, sewage gas, digester gas) and gasification based biopower
  - Ethanol for gasoline blending based on advanced cellulosic-based technology
  - Bio-polymers via fermentation based processes
- These options could provide significant environmental and rural economic benefits by 2010 with aggressive deployment:
  - Over 95 million ton per year reduction in carbon dioxide reduction emissions
  - Significant criteria pollutant emission reductions (390 thousand tons SOx avoided; 440 thousand tons NOx avoided)
  - Around three billion dollar per year added economic activity in rural areas by 2010 from feedstock production alone (primary impact)

... though doubling of use is not likely to happen before 2015.

Achieving significant impact will require the application of new biomass technologies to new applications, in addition to expanding existing ones.

- Existing biomass utilization is based on mature technology and occurs mostly in mature markets (e.g. pulp & paper, starch manufacture)
- Combinations of new technologies and new applications are required to achieve rapid and significant growth in the use of bio-derived energy and products
- Key improvements in technology for targeted markets could aid the implementation of biomass-derived energy and products:
  - Development of lower cost, high-volume, biomass feedstocks (e.g. energy crops) and the establishment of large-scale distribution infrastructure for these biomass feedstocks
  - Development and demonstration of low-cost production processes, which could result in broader cost-competitiveness for biomass-derived power, fuels, and products in the long term (after 2010)
  - Demonstration of the viability and reliability of technologies currently under development
  - Development of optimal information systems to minimize the impact of industry inertia on the market penetration rate of biomass technologies and their products
- Integrated production of energy and products in "Bio-refineries" could contribute to improving the cost competitiveness of biomass options with fossil-based counterparts; this will likely require new inter- and intra industry collaborations

1. This analysis used the projected crude oil and electricity prices in 2010 from the U.S. Energy Information Administration (USEIA) 2001 Energy Outlook, reference case scenario.

To achieve these benefits, significant barriers to implementation must be overcome which will require focused government support.

- Given current projections for crude oil and utility prices,[1] some of the long-term[2] options are expected to require considerable investments by stakeholders and carry higher production costs
- High feedstock and capital recovery costs are the main barriers to significant increases in the use of biomass-derived energy and products in the U.S.:
  - Most current technologies are not cost-competitive with conventional fuels, power, and products in new markets without government support
  - Considerable R&D/D[3] funding will be required to prepare the technologies for commercial application
  - Significant investments (tens of billions of dollars) will be required for plant construction and infrastructure development
- To overcome these barriers, two types of support are critical:
  - Sustained support for crop (resource) production, crop conversion, and product use through tax credits, farm supports, and subsidies will be required if use of biomass-derived energy and products is to be dramatically increased
  - Strong support for R&D/D focused on long-term improvements in technology that will eventually make the technology cost-competitive with conventional fuels and power sources
  - Coordination and careful planning of such support will be critical to its success
- The USDOE, USEPA and USDA could play a key coordinating role with interested industries if such an effort were undertaken

1. This analysis used the projected crude oil and electricity prices in 2010 from the U.S. Energy Information Administration (USEIA) 2001 Annual Energy Outlook, reference case.
2. In this context, near-term means having significant impact before 2010, while long-term means with potentially significant impact in the 2010-2020 timeframe.
3. R&D/D is Research, development and demonstration

Sufficient biomass is expected to be available to more than double the use of biomass but farm-gate prices at high volumes are expected to exceed $20/dry ton.

- Available literature data indicates that over 600 million dry tons of biomass are available within the U.S. at farm-gate prices between 0 and 40 $/dry ton (0 to ~$2.3/GJ or $2.4/MMBTU):
  - Available biomass is defined as a resource that is currently or potentially collectable and not currently used as energy fuel or any beneficial use and is potentially usable (not contaminated)
  - Available biomass in significant quantities below $20/dry ton farm-gate are heterogeneous wastes (Organic municipal solid waste, and urban tree residues)
  - Manure is potentially available in large quantities and at low cost, but off-site applications may be limited due to high transportation costs
  - Based on USDOE agricultural sector model projections, energy crops could be the largest source of biomass at prices in excess of $40/dry ton farm-gate, but energy crops are not currently produced in high volume
- Consistent and homogeneous biomass supplies are only available in large quantities at prices in excess of $20/dry ton farm-gate (e.g. energy crops, corn stover, wheat straw)
- The biomass sources with the highest potential in the 0-40 $/dry ton farm-gate price range are:
  - Corn stover (Great Lakes region: Minnesota, Iowa, Wisconsin, Illinois, Indiana, Ohio and Michigan)
  - Switchgrass (Southeast and West regions: all other states)
  - Organic municipal solid waste (Northeast: New England, New York, Pennsylvania, New Jersey, and Delaware)
  - Forest residues (Northwest :Washington, Oregon, Idaho, and Montana)
- Feedstock cost reductions alone will not enable broader competitiveness for some technologies

Further cost reductions (through more efficient production and co-production with foods & feeds) could broaden the appeal of biomass use in industry.

Bioenergy and bioproducts industries could provide environmental benefits, provided careful management practices are implemented.

- Converting traditional crop lands into perennial energy crop production could yield net benefits in increased soil carbon and nutrients
  - Energy crop production can have erosion concerns unless managed properly
  - Reduced runoff contamination and improved biodiversity are additional potential benefits
- If agricultural residue collection are managed properly soil quality (e.g. organic matter, nutrients, and soil stability) can be maintained and/or improved and increased runoff contamination avoided
- Provided marginal lands need to be carefully managed to realize net benefits from energy crop production
- Forest residue collection must be managed properly to prevent erosion and realize benefits from fire prevention
- Several areas of additional research are necessary to assess the potential environmental impacts and benefits of bioenergy and bioproducts industries
  - The information currently available is based on smaller scale studies
  - Studies at larger scale are needed to validate results and determine landscape scale effects

Several biopower options could provide large fossil energy & greenhouse gas reduction benefits in the short to medium term with modest cost.

- A number of biopower options are commercially available today or can be made available within 1-2 years with minimal technology development
  - Co-firing of solid biomass in coal plants
  - Biogas (digester gas or residue gas) and landfill gas combustion
- These technologies also have fairly attractive economics today, particularly when the fuel source is low or zero cost
- Other biopower technologies have the potential for attractive economics ultimately, but technology development is still required to achieve the needed levels of cost and performance
  - Various gasification options (Refuse derived fuel [RDF], small-scale systems, utility-scale systems, black liquor)
  - Some of these technologies also face significant non-technical hurdles, such as RDF gasification and black liquor gasification
- Several opportunities for biopower are significant and could independently achieve the aggressive goals for biomass use if fully exploited
  - While it is unlikely that any one application will achieve its full technical potential, a combination of applications could meet the aggressive goals
  - The fact that biopower utilizes a variety of feedstocks allows for parallel deployment with minimal inter-application competition
  - Many resources, like landfill gas and onsite residues, are not likely to be in demand for other end uses besides electricity generation
- Biopower has the potential to be cost effective at a variety of scales, from less than 1 MW to 100 MW, depending on the application and technology used
  - This provides the opportunity to utilize feedstocks that might otherwise not be useable for biofuels or bioproducts

Biofuels have significant potential as additive alternatives for conventional petroleum fuels, provided current tax credits are continued.

- Many biofuel options exist that are technically feasible based on fermentation, low-temperature processing and gasification technology
- Due to the huge market potential, biofuels can offer significant potential impact
  - The most likely continued growing market for biofuels is as blending agents
  - Neat fuels are a longer term option
- Ethanol looks particularly attractive as a desirable gasoline additive:
  - Additive markets (as an MTBE replacement) for ethanol would provide ~50% higher value than blending or neat fuel markets primarily due to its oxygenate value on a dollar per gallon basis
  - A progressive reduction in ethanol cost is projected down to about two times the cost of gasoline on a volume basis
  - The ethanol tax credit aids the economics so that today ethanol can be competitive with MTBE
- Other fuels could be considered, but they will face much higher barriers than the ones selected
  - Bio-FT diesel appears to offer another plausible combination of cost and environmental benefits:
  - Bio-FT diesel is considerably more expensive than ethanol is projected to be at about 2.5 times the price of conventional diesel* (on a energy basis)
  - Bio-FT diesel could help to meet new diesel specifications, but it will face tough competition from natural-gas-based FT diesel
  - Extending ethanol tax credits to Bio-FT-Diesel would reduce the price differential to 50-100%

*Based on $21/b oil prices projected by EIA for 2010, for comparison assume price of conventional fuels is roughly proportional to crude oil prices

Ethanol could be close to cost-competitive as an oxygenate additive, but other biofuel options carry a considerable cost premium when valued solely on energy content.

- Biofuels, either as a straight fuel replacement, as a blending stock, or even as an additive, represent very large potential markets for biobased products
- As a straight replacement of conventional fuels, the cost premium of biofuels over conventional fuels exceeds 100% and presents ***the*** most important barrier to the implementation of biofuels as a neat fuel and volume extender
- As a fuel additive, we estimate that bio-ethanol could be produced for a very modest cost-premium over MTBE; the current ethanol tax credit bridges that gap
- This, together with the alternative fuel tax credits available in some states and the planned phase-out of MTBE make bio-ethanol a plausible biofuel option for blending for oxygenate applications
- It is unclear whether ethanol is as competitive when just valued on its octane value (compared to its oxygenate value) excluding any tax credits
- The tax credit could be reduced further if aggressive R&D&D on cellulosic ethanol technology reduces costs associated with feedstock, capital, and non-fuel operating
- In niche applications, where advantage can be taken of other benefits of bio-ethanol production, lower-overall-cost solutions could be found now:
  - Production of bio-ethanol from waste-streams while recovering other valuables from these stream
  - Use of forest residues for ethanol production that must be utilized (e.g. in California)
  - Use of existing infrastructure (e.g. use of idled paper mills or biomass power plants)

Several bioproducts appear to be able to approach cost and performance competitiveness with conventional products.

- Fermentation-based polymer building blocks can offer cost-competitive routes to commodity plastics provided key technology challenges are met
- Selected pyrolysis-based and low-temperature processing based products (using woody biomass and lipids) may be competitive in medium to large markets
- Bioproducts derived by C_1-chemistry do not appear to come close to being cost-competitive on a stand alone basis because of lack of economy of scale in the processing steps
- Biotechnology could lead to a broader range of products that could be produced through physical separation or fermentation
- Further development is required for large scale energy efficient reactors, that allow easy and flexible operation and integration in "bio-refineries", especially for fermentation processes
- For commodity markets, availability of the desired feedstock at low cost and in sufficient quantities is critical

Several bioproducts appear to be able to approach cost and performance competitiveness with conventional products.

- Fermentation-based polymer building blocks can could offer cost-competitive routes to commodity plastics provided key technology challenges are met:
  - High primary product yield and concentration
  - Large-scale, continuous-reactor production technology
  - Ability to use low-cost feedstock (i.e. waste or cheap to grow feedstock)
- Selected pyrolysis-based and low-temperature-processing-based products may be competitive in niche markets:
  - Phenolics from wood pyrolysis
  - Lipid based products such as fatty alcohols, acids, and esters
- Bioproducts based on C_1-chemistry do not appear to come close to being cost-competitive:
  - Should still be considered as co-products in FT-diesel or DME production (bio-refinery)
  - Require similar market premium or subsidy as most competitive fuels

To achieve the necessary performance and cost improvements both improved organisms and improved reactor engineering will be required.

- Process engineering can be used to achieve the capacity scale needed for cost competitiveness
  - Continuous processing is required for commodity market competitiveness
  - Reaction scale and reactor type have to be sufficient to match both cost requirements and market capacity
  - Process engineering can influence product concentration and product yields
- Genetic engineering of the organisms determines to a large extent, achievable product yields, product concentrations and by-product selectivity
  - Product concentration has to be high enough to allow for effective and simple purification technology
  - Product yield should be high enough to allow for efficient substrate and equipment utilization
  - Product selectivity will be determined in large part by the metabolic pathways used to make the product by the organism
- Low cost (and available) feedstocks are required but alone will not ensure commodity scale cost competitiveness

In the long term, further advances in genetics and bioengineering could broaden the appeal of bioproducts.

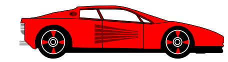
- Biotechnology could lead to a broader range of products that could be produced through physical separation or fermentation:
  - Currently, fermentation based products are limited to a few products that are biochemically feasible to produce
  - Agricultural biotechnology efforts utilizing plant production could lead to success for a much wider spectrum of potential products from physical separation and fermentation
- Further development of large scale energy efficient reactors, that allow easy and flexible operation and integration in “bio refineries”
- Development of stable production organism strains that allow for:
  - Sufficient product yield
  - Sufficient product concentration
  - Desired feedstock use
- Availability of the desired feedstock cost at low cost and sufficient quantities

A number of uncertain factors could considerably benefit or detract from the growth and impact of biomass-derived energy and products.

- Conventional energy prices:
  - Developments in ***crude oil prices*** are likely to have considerable impact on all options, particularly on the fuels and products options, which are competing directly with petroleum-based products
  - ***Gasoline shortages*** in 2000 due in part to localized rulemaking leading to boutique fuel requirements provide an opportunity for biofuels
  - Uncertainty in ***natural gas and electric power prices*** also could have a significant impact on bio-energy viability, particularly for biopower options
  - Fluctuations in prices cause uncertainty which concerns investors in biomass plants
- Political factors:
  - The situation around ***RFG oxygenates (MTBE)*** is unresolved and though it currently appears favorable for biofuels, other outcomes are still possible
  - ***Tax incentives for biofuels*** have been rather stable over the past fifteen years
  - Discontinuation of PURPA support for biopower plants has caused concern over long-term reliability of government support
- Public opinion:
  - Public environmental concern drives most interest in biomass-derived energy and products
  - Until recently ***use of Genetically Modified-crops*** for non-human food-uses was considered uncontroversial in the U.S., but experience with GM-corn crossfertilization has called this into question; this could have significant ramifications for the feasibility of certain crop improvement efforts for energy and product applications
  - NIMBY concerns for waste to energy facilities might affect RDF biopower options
  - Impact of biomass production/collection/transport on local environment may be a concern

Biomass power use could be doubled by 2010 but this would require that several factors combine favorably in addition to strong government support.

- Biomass co-firing with coal is critical for rapid, near-term growth and is responsible for over 50% of the growth
  - Direct co-firing using non-woody fuels will likely be required, which will itself require further technology development and demonstration
  - May be potential for synergy with new clean-coal-based technologies (not included in analysis)
- Biomass integrated gasification combined cycle (BIGCC) technology in the pulp & paper industry is the second most important contributor with almost 20%of the growth
- Landfill gas and digester gas also figure prominently in the aggressive growth scenario for early growth
  - Technologies are available today
  - USDOE should focus on removing economic or regulatory barriers
- Other gasification technologies are less important in the near-term but are important for sustained growth:
  - Other industries that generate residues are expected to contribute modestly throughout the 2000-2020 timeframe
  - RDF could become a significant source of biopower in the long term, provided technical and environmental issues are addressed successfully
  - Gasification for co-firing could become significant beyond 2010, in both coal- and natural gas-fired power plants
- Implementation of the Aggressive Growth scenario would require several successful simultaneous developments:
  - Biomass supply infrastructure to develop rapidly if the market potential is to be realized
  - Successful development of gasification technology
  - Successful elimination of regulatory barriers to biopower implementation
- It would also require significant government support to overcome the cost difference of some longer-term options and expected market prices



Biofuel utilization could be tripled by 2010, albeit at a high cost.

- In a Business As Usual scenario, increases in production and use of biofuels would be approximately 800 million gallons ethanol by 2010 (Over baseline consumption):
  - Limited by current technology cost and government incentives
  - Gasification-based technology is not likely to become commercial
  - Ethanol looks like the preferred MTBE replacement but die is not cast
  - Implementation of ethanol as an MTBE replacement in California is thought to have net positive impact on California economy (but not necessarily on the country)
- Achieving tripling of biofuels use by 2010 would require:
  - Strong regulatory support for bio-derived oxygenates for RFG nationwide
  - Highly successful technology development and cost reduction
  - Highly packaged plants for integration with conventional blending and distribution terminals
  - Continued and stable incentives for biofuel productions
- However, the cost associated with achieving this impact rapidly would be very high:
  - Cost of current bio-ethanol requires a $0.54 per gallon tax credit
  - Additional demand (especially if MTBE were phase out in the nation and an oxygenate requirement remained) would put pressure on ethanol markets and could possibly increase the price
  - Achieving a tripling goal would require construction of cellulosic ethanol facilities based on first generation technology

Bioproducts use could be tripled by 2020 requiring aggressive technology and market development but not sustained government support.

- In a Business as Usual scenario, bioproducts would capture a small fraction of the growth volume of specific chemical markets
  - No current large-scale incentives for bioproduct use (such as tax credits for ethanol fuel, green power and other renewable power credits)
  - Most of the growth comes from traditional bioproduct growth (e.g. starches) and from products produced by physical extraction (e.g. seed oils), in which bioproducts already have a high market share
  - Limited potential market for low-hanging fruit
  - Technologies with greater potential impact do not reach the market until much later and will penetrate the market slowly
  - Even in the BAU scenario, however, we expect bioproducts to have a considerable impact in the longer term, since competitive economics will be achieved for broad-based application of bioproducts to polymers and solvents
- With aggressive technology and market development and some government support (but not necessarily product price support), a significant impact (even tripling) may be achievable by 2020, though not by 2010
  - Technologies with high impact potential (such as fermentation-based polymers and monomers) would become commercially available in the 2010 timeframe
  - With plant construction and market penetration inertia significant market penetration would not be achievable before 2020
- Given the limited volume of product markets (as compared with fuels and power markets) the relative impact of bioproducts on greenhouse gas emissions and rural economic development can be considerable, but not large in absolute terms
  - Because of the more limited scale, at least early facilities may well be integrated into existing chemicals plants or into existing corn or paper mills
  - The projected economics of bioproducts will eventually not require sustained government financial support for several of the options, resulting in potentially very modest cost for investment, but not for sustained subsidies

A selected set of policy options appear to be critical to achieving success in implementing increases in biomass use.

- R&D support is critical to achieve the necessary and sustained breakthrough improvements in technology performance and cost
- Voluntary agreements and public/private partnerships are critical to marshalling the level of resources necessary for large-scale implementation efficiently
- Tax measures can be used to entice early adopters and or bridge the cost-competitiveness gap for selected biomass options
- Information programs and consumer education programs are critical to internalizing the benefits of biobased energy and products in terms of product premiums
- Direct subsidies or price controls are likely the only way to have a chance at achieving the tripling goal can be achieved by 2020 in all sectors
- Renewable content standards have been proposed and are possibly a good alternative to direct support
- Sustained support, while not desirable from a global, free market perspective, may in fact be sensible on a national or regional basis